Supreme Court, U. S.
FILED
DEC 19 1979
MICHAEL RODAK, JR., CLERK

IN THE

Supreme Court of the United States

OCTOBER TERM, 1979

No. 79-962

TENNESSEE GAS PIPELINE COMPANY,
a Division of Tenneco Inc.,
Petitioner,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

APPENDIX TO PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

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APPENDIX A

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 77-1496

TENNESSEE GAS PIPELINE COMPANY,
a division of Tenneco Inc., PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK
ENTEX, INC.
COLUMBIA GAS TRANSMISSION COMPANY
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
NORTHERN ILLLINOIS GAS COMPANY
NEW ENGLAND CUSTOMER GROUP (BAY STATE GAS CO.),
INTERVENORS

No. 77-1498

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

TENNESSEE GAS PIPELINE COMPANY
COLUMBIA GAS TRANSMISSION CORPORATION
NEW ENGLAND CUSTOMER GROUP, ET AL.
NORTHERN ILLINOIS GAS CO.
PUBLIC SERVICE ELECTRIC AND GAS CO., INTERVENORS

No. 77-1653

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

COLUMBIA GAS TRANSMISSION CORP.
TENNESSEE GAS PIPELINE CO.
PUBLIC SERVICE ELECTRIC AND GAS CO.
PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,
INTERVENORS

No. 77-1712

TRANSCONTINENTAL GAS PIPE LINE CORPORATION,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

COLUMBIA GAS TRANSMISSION CORP.
UNITED CITIES GAS COMPANY
PUBLIC SERVICE ELECTRIC & GAS COMPANY
TENNESSEE GAS PIPELINE CO.
PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,
INTERVENORS

No. 77-1719

MICHIGAN WISCONSIN PIPE LINE COMPANY, PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

WISCONSIN NATURAL GAS CO.
ASSOCIATED NATURAL GAS CO.
MICHIGAN GAS UTILITIES CO., INTERVENORS

Petitions for Review of Orders of the
Federal Energy Regulatory Commission

Argued September 29, 1978

Decided June 20, 1979

Harold L. Talisman with whom *Melvin Richter, Dale A. Wright, Patricia A. Curran, Terence J. Collins, Gregory Grady* and *Lilyan G. Sibert* were on the brief, for Tennessee Gas Pipeline Company, petitioner in No. 77-1496, intervenor in Nos. 77-1498, 77-1653 and 77-1712 and amicus curiae in No. 77-1719.

Richard J. Flynn with whom *Frederic G. Berner, Jr.* and *Charles V. Shannon* were on the brief, for Michigan Wisconsin Pipe Line Company, petitioner in No. 77-1719 and amicus curiae in No. 77-1496.

Thomas F. Ryan, Jr. with whom *Robert G. Hardy* was on the brief, for Transcontinental Gas Pipe Line Corporation, petitioner in No. 77-1712.

Edward W. Hengerer and *Norman A. Pedersen*, Attorneys, Federal Energy Regulatory Commission, with whom *Howard E. Shapiro*, Solicitor, and *Philip R. Tel-*

leen, Attorney, Federal Energy Regulatory Commission, were on the brief, for respondents.

Richard A. Solomon with whom *Peter H. Schiff* and *Sheila S. Hollis* were on the brief, for Public Service Commission of the State of New York, petitioner in No. 77-1498 and intervenor in Nos. 77-1496 and 77-1712.

Jerome J. McGrath, John H. Cheatham, III and *J. Evans Attwell* were on the brief, for petitioner Interstate Natural Gas Association of America in No. 77-1653.

John D. Daly and *Giles D. H. Snyder* and *Stephen J. Small* were on the brief for intervenor Columbia Gas Transmission Corporation in Nos. 77-1496, 77-1498, 77-1653 and 77-1712.

Robert H. Gorske was on the brief, for intervenor Wisconsin Natural Gas Company in No. 77-1719.

Irving Jacob Golub, Stephen A. Wakefield, William B. Cassin and *Phillip D. Endom* were on the brief, for amicus curiae United Gas Pipe Line Company in Nos. 77-1496, 77-1498 and 77-1653.

Also *Allan Abbot Tuttle, Robert W. Purdue* and *Dennis Lane*, Attorneys, Federal Energy Regulatory Commission, entered appearances for respondent.

Also *Paul W. Fox* and *John W. Glendening, Jr.* for intervenor New England Customer Group in Nos. 77-1496 and 77-1498.

Also *J. Stanley Stroud* entered an appearance for intervenor Northern Illinois Gas Company in Nos. 77-1496 and 77-1498.

Also *Carl W. Ulrich, William R. Duff, Edward S. Kirby* and *James R. Lacey* entered appearances for intervenor Public Service Electric and Gas Company in Nos. 77-1496, 77-1498, 77-1653 and 77-1712.

Also *Michael J. Manning* and *Patrick J. Keeley* entered appearances for intervenor Entex, Inc. in No. 77-1496.

Also *Jack M. Irion* entered an appearance for intervenor United Cities Gas Company in No. 77-1712.

Also *Richard M. Merriman, J. Richard Tiano* and *Richard T. Witt* entered appearances for intervenors Associated Natural Gas Company and Michigan Gas Utilities Company in No. 77-1719.

Before: LEVENTHAL and WILKEY, *Circuit Judges*, and HAROLD GREENE,* *District Judge*, United States District Court for the District of Columbia.

Opinion for the Court filed by *Circuit Judge* LEVENTHAL, in which *Circuit Judge* WILKEY and *District Judge* GREENE join.

Concurring opinion filed by *Circuit Judge* WILKEY.

LEVENTHAL, *Circuit Judge*: We consider petitions of natural gas pipeline companies [1] for review of Federal Power Commission [2] rate making orders. The common

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* Sitting by designation pursuant to 28 U.S.C. § 292(a) (1976).

[1] In addition to the principal pipeline petitioners, Tennessee Gas Pipeline Company (No. 77-1496) ("Tennessee"), Transcontinental Gas Pipe Line Corporation (No. 77-1712) ("Transco"), Michigan Wisconsin Pipe Line Company (No. 77-1719) ("Michigan-Wisconsin"), there are petitions by the Interstate Natural Gas Association of America (No. 77-1653) ("INGAA"), Columbia Gas Transmission Corporation (Intervenor in No. 77-1496 *et al.*) ("Columbia"), and the Public Service Commission of the State of New York (No. 77-1498) ("PSC"). There also have been various cross-interventions by the parties.

[2] The Federal Power Commission went out of existence in the fall of 1977. The Department of Energy Reorganization Act of 1977, P.L. 95-91, 91 Stat. 565, *codified at* 42 U.S.C. §§ 7107 *ea seq.* (1978), transferred most of the FPC's func-

element in these companion cases is the treatment of "advance payments," pre-payments for future deliveries of natural gas made by the pipelines in the context of an experimental "advance payment program," which was designed to facilitate capital formation by producers to finance development and production of additional gas supplies, thus helping to alleviate the natural gas shortage. In formulating "just and reasonable" pipeline rates in each case, the Commission denied rate base treatment for various expenditures. It deferred inclusion in rate base for advance payments made during the test period and not appropriately expended by the recipient producers within 30-days of the close of that period. We find that the Commission failed to administer the advance payment program with the required flexibility and thus remand the treatment of advance payments for further consideration. In certain respects, as will be noted, we affirm the Commission's other determinations.

I. Front-End Advance Payments to Domestic Producers

A. *General Background*

The unhappy saga of the advance payment program has been detailed by this court on other occasions.[3] Con-

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tions, including its rate making authority under both the Federal Power Act and the Natural Gas Act, to the newly created Federal Energy Regulatory Commission (FERC). 42 U.S.C.A. §§ 7172(a)(1)(B), (C) (1977). This change in administration has no effect on the instant litigation, save for the appropriate substitution of parties.

[3] *See* The Second National Natural Gas Rate Cases, 186 U.S.App.D.C. 23, 59-64, 567 F.2d 1016, 1052-57 (1977), *cert. denied*, 435 U.S. 907 (1978); United Gas Pipe Line Co. v. FPC, 179 U.S.App.D.C. 274, 276, 551 F.2d 460, 462 (1977); Michigan Wisconsin Gas Pipe Line Co. v. FPC, 171 U.S.App.D.C. 352, 353-54, 520 F.2d 84, 85-86 (1975); Public Service Com'n, State of N.Y. v. FPC, 167 U.S.App.D.C. 100, 511 F.2d 338 (1975) [hereafter cited as "*PSC (Advance Payments) II*"]; Public Service Com'n, State of N.Y. v. FPC, 151 U.S. App.D.C. 307, 467 F.2d 361 (1972) [hereafter cited as "*PSC (Advance Payments) I*"].

ceived as one method of alleviating the impending natural gas shortage, the program was initiated in 1970 and was governed successively by a series of five "advance payment orders" until its termination at the end of 1975.[4] As originally formulated and approved by this court, the program was designed to facilitate capital formation by producers to finance development and production of new gas supplies.[5] It was contemplated that pipelines would provide production capital in the form

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[4] Order No. 410, Accounting and Rate Treatment of Advance Payments to Suppliers for Gas and Amending F.P.C. Form No. 2, Docket No. R-380, 44 FPC 1142 (1970) (governing advances made pursuant to contracts entered after October 2, 1970) [hereafter cited as "Order No. 410"]; Order No. 410-A, Accounting and Rate Treatment of Advance Payments to Suppliers for Gas, and Amending F.P.C. Form No. 2, Docket No. R-380, 45 FPC 135 (1971) (amending the treatment of advance payments governed by Order No. 410) [hereafter cited as "Order No. 410-A"]; Order No. 441, Accounting and Rate Treatment of Advance Payments to Suppliers for Exploration and Lease Acquisition of Gas Producing Properties, Docket No. 4-411, 46 FPC 1178 (1971) (governing advance payments contracts executed between November 10, 1971 and December 31, 1972) [hereafter cited as "Order No. 441"]; Order No. 465, Accounting and Rate Treatment of Advance Payments Included in Account 166, Advance Payments for Gas Development and Production, Docket No. R-411, 48 FPC 1550 (1972) (governing contracts executed between January 1, 1973 and December 31, 1973) [hereafter cited as "Order No. 465"]; Order No. 499, Accounting and Rate Treatment of Advances Included in Account No. 166, Advances for Gas Exploration, Development and Production, Docket No. RM74-4, 50 FPC 2111 (1973) (governing contracts executed between January 1, 1974 and December 31, 1975) [hereafter cited as "Order No. 499"].

[5] *PSC (Advance Payments) I*, *supra* note 3, 151 U.S.App. D.C. at 309, 467 F.2d at 363.

of pre-payments to producers (advance payments) for future deliveries of natural gas. The order launching the program provided that such payments could be capitalized and included in the pipeline's rate base subject to qualifications, including the requirement that advances must be "reasonable and appropriate." [6] The orders also specified those producer expenditures permissible under the program ("qualifying expenditures"). Producers could be expected to seek advance payments because the advances would provide them with a source of interest-free capital.[7] It was anticipated that pipeline participation in the program also would be assured if pipeline rates could reflect a return on qualifying advance payments.[8] Current purchasers from the pipeline would shoulder, in the rates they paid, the "carrying charges" on these interest-free loans to producers, though the benefits from expansion of natural gas supplies would

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[6] Order No. 410, *supra* note 4, 44 FPC at 1144. Advance payments were to be drawn down and removed from Account 166, Advance Payments for Gas, as gas deliveries commenced or as the pipeline was reimbursed in consideration other than gas. The significant express qualifications governing advances under the various orders are described in note 34 *infra*.

[7] *See* Order No. 465, *supra* note 4, 48 FPC at 1554.

[8] The "cost" to the pipeline of an advance payment was the cost of financing the amount advanced, a factor principally determined by interest rates in the bond market. The "cost" to rate payers was determined by the rate of return allowed on the pipeline's rate base. A differential between the allowed rate of return and the prevailing interest rate in capital markets provided some opportunity for successful arbitrage, but as interest rates rose during the relevant period this incentive was minimized. The principal incentive for pipeline participation lay in their ability to secure gas reserves for the future while transferring to the rate payer the added cost of making pre-payments (advance payments) for the gas.

flow to future, not current, rate payers.[9] This departure from the usual rule of public utility regulation (that current rates should reflect the cost of supplying service to current rate payers) was thought justified by the "public interest in enlarging the field supply of natural gas, needed for existing facilities and contracts." [10]

The program was conditionally approved by this court in *Public Service Commission, State of New York* v. *FPC* [*PSC* (*Advance Payments*) *I*],[11] as a "justifiable experiment in the continuing search for solutions to our nation's critical shortage of natural gas." [12] Resolving doubts in favor of the program, we stressed its experi-

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[9] Qualifying advance payments had to be made prior to deliveries under the advance payment contract. *See, e.g.*, Order No. 465, *supra* note 4, 48 FPC at 1556. Substantial lag times were inevitable between the date of the advance and its full repayment in gas, especially if the advance were made to fund exploration or other pre-production producer expenditures. *See id.* at 1553 (FPC assumption that all pre-Order No. 441 advances are fully recovered on the average in five years, with a one-year lag between the advance and commencement of recoupment). Where "front-end" advances were involved, the time between the date of advance and its full repayment in gas was considerably extended. For example, most of the advance payments excluded for a period from Tennessee's rate base, though advanced in 1973, were not even fully utilized by the recipient producers until 1975, and the weighted average lag time between the end of the applicable test period and the date when Tennessee's producers would require the advance to cover costs was calculated to be 22.8 months. JA in No. 77-1496, *et al.* at 254, 256 (testimony of Staff witness Robert H. Benna, unrebutted by petitioners in this respect); *see* FERC Br. in No. 77-1496, *et al.* at 36.

[10] *PSC (Advance Payments) I*, *supra* note 3, at 316, 467 F.2d at 370.

[11] 151 U.S.App.D.C. 307, 467 F.2d 361 (1972).

[12] *Id.* at 317, 467 F.2d at 371 (on petition for rehearing).

mental character and the need for flexibility and re-evaluation as it evolved. We perceived the three advance payment orders that had been issued as of that time [13] "as an on-going effort by the FPC to determine experimentally the proper solution with regard to advance payments to help alleviate the gas shortage," and we were "impressed with the fact that the FPC [had] demonstrated a willingness to assimilate criticism . . . and adjust its treatment of advance payments to conform with the realities of the natural gas market." [14] We emphasized that the agency, in reaching "an accommodation of conflicting interests," was "making policy decisions of the type it was created to make." [15] But this judicial approval was predicated on the Commission's willingness to continue to respond to "the realities of the natural gas market" and to modify the program in light of accumulated experience. We reiterated these concerns in our response to New York Public Service Commission's petition for rehearing.[16]

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[13] Orders No. 410, No. 410-A, and No. 441, *supra* note 4.

[14] *PSC (Advance Payments) I*, *supra* note 3, 151 U.S.App. D.C. at 313, 467 F.2d at 367.

[15] *Id.*

[16] *Id.* at 317, 467 F.2d at 371:

> One of the important factors in reaching our decision was the temporary character of the FPC order under review (Order 441 remains in effect only through 31 December 1972), and our belief that it represented a justifiable experiment in the continuing search for solutions to our nation's critical shortage of natural gas. . . . Fundamental to the concept of any experiment is the assumption that the data developed from the experience thereunder will be subjected to meaningful review, analysis, and evaluation before the experimental practice is allowed to continue or to become institutionalized as a more permanent procedure. . . . We would accordingly expect that the FPC will not continue, or extend the effective date of, the practices authorized by Order 441 without further proceedings in which New York and all other interested parties will be given the opportunity to demonstrate the effectiveness or the futility of this experiment.

The advance payment order approved by our March 1972 ruling in *PSC (Advance Payments) I* expired at the end of that year. It was replaced in turn by the two orders pertinent to the instant cases, Order No. 465,[17] governing advance payments made during 1973, and Order No. 499,[18] governing the 1974-75 period. When the program again came before this court in *Public Service Commission, State of New York* v. *FPC* [*PSC (Advance Payments) II*],[19] we ruled that the Commission had failed in its obligation "to engage in 'meaningful review, analysis and evaluation' of the experience under the advance payments program" [20] and to "adjust its treatment of advance payments to conform with the realities of the natural gas market." [21] In our view, "[t]he data presented by the Commission as a justification of its repeated extensions of the advance payments program provide[d] an inadequate basis from which 'to determine whether its justifying objectives [were] being satisfactorily met at an acceptable level of ultimate economic cost to the nation's gas consumers.'" [22] Accordingly, we remanded the record for further evidence and

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[17] *See* note 4 *supra*.

[18] *See id.*

[19] 167 U.S.App.D.C. 100, 511 F.2d 338 (1975).

[20] *Id.* at 104, 511 F.2d at 342 (quoting from *PSC (Advance Payments) I* statement on petition for rehearing, note 16 *supra*).

[21] *Id.* at 105, 511 F.2d at 343.

[22] *Id.* at 104, 511 F.2d at 342 (quoting from *PSC (Advance Payments) I* statement on petition for rehearing, note 16 *supra*).

consideration by the FPC. In light of its subsequent reevaluation, the agency allowed the program to expire upon termination of Order No. 499 on December 31, 1975.[23]

Although the program has been terminated, existing advance payment contracts retain their vitality,[24] and continued administration is required as pipelines file with the FERC for jurisdictional rate increases. In such rate-making proceedings the Commission has been called upon to determine whether specific advance payments qualify for rate base treatment under the terms of the applicable advance payment orders. This is the posture of the cases here under review.

B. *Nature of Front-end Advance Payments*

The central controversy in these cases involves the temporary exclusion from rate base of certain "front-end advance payments" made in the United States.[25]

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[23] *See* Advances for Gas Exploration, Development and Production, Docket Nos. R-411 & RM74-4 (orders issued Dec. 31, 1975 and Feb. 27, 1976).

[24] *Id.*

[25] The first of the two advance payment orders pertinent to these cases restricted its coverage to advances made to producers within the lower 48 states. Order No. 465, *supra* note 4, 50 FPC at 1555. The second pertinent order made accommodation for advances to producers in Alaska. Order No. 499, *supra* note 4, 50 FPC at 2116.

One of these cases, No. 77-1496 *et al.*, also involves exclusion from rate base of advances made to Canadian producers, but the Commission's decision was controlled by different considerations since advances to producers on the North American continent outside the United States were eligible for rate base treatment but only on a case-by-case basis. Advances to Suppliers for Gas Outside Continental United States, Docket No. R-466, 38 Fed. Reg. 1055-56 (1973) (notice of rulemaking). This issue is treated in section II-A *infra*.

These are a particular class of "advance payments." In general, the program provided for "advance payments" in the sense that the payments were authorized to be made in advance of the delivery of gas supplies. The focus of concern in these cases is the so-called "front-end advance payment," which identifies a transfer to the producer not only prior to gas deliveries, but also prior to any producer expenditures associated with ultimate production of the gas.

An advance payment has two aspects, and provides a dual benefit to the recipient producer. First, it is a *source of capital*, which supplements the funds available to producers for development and production expenditures. It is a loan, but one shaped as a pre-payment to be credited against the purchase price of gas that will flow from successful development efforts. Second, it is an *interest-free* loan. When an advance payment substitutes for capital raised in financial markets, it relieves the producer of financing costs. There is an extra benefit to the producer in that the rate set for the producer by the Commission incorporates an allowance for financing cost, and no reduction in that rate is required on account of the fact that part of the producer's financing is cost-free.[26] Thus, advance payments provide a

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[26] *See, e.g.*, JA in No. 77-1712 at 148-49, Transcontinental Gas Pipe Line Corporation, Docket Nos. RP74-48 and PR75-3, Presiding Administrative Law Judge's Initial Decision on Reserved Issues 31-32 (Dec. 22, 1975) [hereafter cited as "Transcontinental Initial Decision"] ("[T]he producer has interest-free use of the funds until the day they must be spent on eliciting gas, and this is a substantial bonus added to the price he will receive for the gas from the pipeline. The pipeline receives no discount upon that price because its funds financed the producer's venture. And the full price, commonly the highest price permissible under FPC regulations, is ultimately paid by the pipeline's customers."); JA in No. 77-1719 at 111, Michigan Wisconsin Pipe Line Co., Docket No. CP70-

"bonus" to producers in the amount of the interest factor, an amount which is never refunded.

In the Commission's view, the objective of the advance payment program was to expedite the development of gas supply through the mechanism of providing producers an additional *source of capital.* In theory, the increased availability of capital would encourage investment, which in turn would yield additional gas supply. The interest factor, and the "bonus" which it provided to producers, has been construed as a subsidiary element designed to provide incentive for producer participation, a necessary cost to achieve the desired benefit.[27]

The Commission has come to focus on front-end advance payments as providing a still further bonus to the producer—not only the interest-free availability of funds during use for gas development, but their availability for some period prior to the time of "qualifying expenditure" by the producer. The Commission has recognized that capital formation and the pertinent qualifying expenditure may be facilitated by the transfer of an advance to the producer a "reasonable time" prior to the expenditure. However, the Commission has endeavored through administration of the program to protect rate payers from the cost of advance payments held by producers for any "unreasonable" front-end period. Advance payments that were made (in the Commission's view) an "unreasonable" time prior to their appropriate expendi-

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22, Initial Decision Upon Inclusion of Advance Payments in Rate Base 7 (Feb. 27, 1976) [hereafter cited as "Michigan-Wisconsin Initial Decision"], JA in No. 77-1719 at 111 ("The use of money for a period of time is itself worth money. The advance payments at issue in this proceeding necessarily involve the payment of substantial additional compensation to the producers above and beyond the established price for gas that they may discover and sell to the pipeline.").

[27] *See* Order No. 465, *supra* note 4, 48 FPC at 1554.

ture have been labeled "extravagant" by the agency. Since the term "extravagant" begs the question, these payments will be referred to in this opinion as "extended front-end advance payments" or "extended front-end advances."

C. *The Critical Timing Requirement*

Distilled to its essence, this case involves two questions: (1) whether the rate base treatment contemplated by the program was inherently limited to advance payments made no more than a "reasonable time" prior to their appropriate expenditure; and, (2) whether, if such a limitation existed, the Commission acted within its discretion in defining the permissible interval solely in terms of traditional line-of-credit financing practices.

The timing element has assumed paramount importance due to the response of both pipelines and producers to the realities of the natural gas market in the context of the advance payment program. In an unregulated economic environment, a period of supply shortage may be expected to stimulate a rise in price until supply and demand are once again in equilibrium. But on sales of natural gas within FERC jurisdiction, both producers and pipelines are foreclosed from an unencumbered response to economic forces. Unless specifically excepted, producers must sell gas, and pipelines must buy it, at regulated rates that may fall well below a "free-market" price.[28] Further, the law imposes on the pipelines an

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[28] Section 4(a) of the Natural Gas Act, 15 U.S.C. § 717c(a) (1976), provides that "[a]ll rates and charges made, demanded, or received . . . shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful." Section 5, 15 U.S.C. § 717d (1976), authorizes the Commission to review rates and set them at just and reasonable levels. Section 7(c), 15 U.S.C. § 717f(c) (1976),

enforceable obligation to resist any temptation to acquiesce in unlawful producer demands and to bid against each other for available supplies of gas by offering higher prices or their equivalents.[29] Still, the sanctions available to the FERC have their limitations, and even in the regulatory context market pressures retain some vitality.[30]

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requires that new gas be sold under certificates of "public convenience and necessity." The Commission's power to exempt producers and pipelines from the regime of just and reasonable rate regulation is limited. *See generally* FPC v. Texaco Inc., 417 U.S. 380 (1974); Consumer Federation of America v. FPC, 169 U.S.App.D.C. 116, 515 F.2d 347, *cert. denied*, 423 U.S. 906 (1975).

[29] *See* Natural Gas Act, §§ 20, 21, 15 U.S.C. §§ 717s, 717t (1976).

[30] Pursuant to section 4(e) of the Natural Gas Act, 15 U.S.C. § 717c(e) (1976), the Commission may suspend a filing for a jurisdictional rate for up to five months. At the end of the suspension period, the rate may go into effect, subject to refund. Pipeline expenditures for the purchase of gas beyond just and reasonable prices may be denied reimbursement (*i.e.*, ordered for refund) and the pipeline's investors, rather than its rate payers, may have to bear the disallowed cost. Section 20 of the Act, 15 U.S.C. § 717s (1976), allows the Commission to seek an injunction from a district court to restrain on-going or prospective violations of the Act's provisions. Section 21, 15 U.S.C. § 717t (1976), subjects to criminal penalties "[a]ny person who willfully and knowingly does or causes or suffers to be done any act, matter, or thing in this chapter prohibited or declared to be unlawful," and subjects to modest per diem fines "[a]ny person who willfully and knowingly violates any rule, regulation, restriction, condition, or order made or imposed by the Commission under authority of this chapter." Despite these deterrents to the knowing payment of higher than just and reasonable prices for natural gas, the Commission cannot take the ill-gotten gas away from the offending pipeline once it has flowed to its customers. One may anticipate circumstances where a pipeline's investors might determine in their sound business

The advance payment orders did not specify the permissible interval between the advance and its appropriate expenditure. Perhaps emboldened by this indefiniteness, producers pressed their bargaining advantage, inducing pipelines to make advances long before the funds were used for qualifying expenditures. These advances, certain of which the Commission has labeled "extravagant," and which we refer to as "extended front-end advances," gave producers valuable interest-free funds for their unrestricted use during the interim period. By this mechanism the price of natural gas effectively was raised above the regulatory ceiling.[31] Competition for needed gas supplies motivated pipelines to acquiesce in exorbitant producer demands. The belief (or hope) that the Commission would permit rate-base treatment of extended front-end advances, thus passing on the competitive cost to the rate payers, may have contributed to the pipelines' weakened resistance. Whatever the causes, extended front-end advance payments emerged in the market and are referred to in the testimony of witnesses for the pipelines as a "term of trade" arising during the period relevant to these cases.[32]

The Commission has administered the advance payment program to defer inclusion in rate base of a pipeline's front-end advances until the test period in which those advances were used by the recipient producers for appropriate purposes. The Commission has relied on its construction of the general objectives of the program and on the administrative discretion inherent in an announced general policy that it would include in the rate

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judgment to take the risks associated with obtaining needed gas supplies, at least where there is a colorable legal argument that questionable expenditures are permissible.

[31] *See* note 26 *supra*.

[32] *See, e.g.*, Opinion No. 769-A, Tennessee Gas Pipeline Company, Docket No. RP73-113, Opinion and Order Denying Rehearing 3 (May 31, 1977) [hereafter cited as "Opinion No. 769-A"], JA in No. 77-1496 *et al.* at 394.

base only those advances found "reasonable and appropriate."

The initial advance payment order established Account 166, Advance Payments for Gas, and provided that "advance payments for gas would be recorded as prepayments and unrecovered advance payments would be included in the rate base as part of working capital." [33] Various express conditions limited the advance payments that would be considered for inclusion in rate base. Some of these conditions were modified in the subsequent advance payment orders.[34] Each of the orders stated that

[33] Order No. 410, *supra* note 4, 44 FPC at 1143.

[34] Order No. 410 encompassed advance payments to independent or affiliated producers for exploration, lease acquisition, development, or production of natural gas, "when such advance payments are to be repaid by delivery of gas." *Id.* at 1146. Advances had to be fully recovered within a "reasonable period of time following commencement of deliveries," and in any case "within a 5-year period." *Id.* The rate base account had to be credited by the amount of non-recoverable advances. *Id.*

Order No. 410-A, *supra* note 4, suspended rate-base treatment for advances to affiliated producers for exploration and lease acquisition costs. 45 FPC 135 (1971). Order No. 441, *supra* note 4, limited the program to the period ending Dec. 31, 1972, and denied rate-base treatment to all advances for exploration and lease acquisition, as well as payments to both affiliated and independent producers which resulted in a working interest. 46 FPC at 1180-81. Where economic interests other than a working interest were received by a pipeline as a result of an advance payment properly includable in the rate base, any realization therefrom was to be treated so as to reduce the pipeline's most of service. *Id.* at 1181. Advance payments might be repaid by delivery of natural gas or by other consideration, and full repayment was required within five years from the date gas deliveries commenced or the date it was determined that recovery would be in other than gas. *Id.* at 1180.

Order No. 465, *supra* note 4. extended the program for one year and reallowed rate-base treatment of advances for exploration while continuing to deny it for lease acquisition costs. 48 FPC at 1554. Advances by a pipeline to an affiliated producer were eligible for rate base treatment, even if the affiliate obtained a working interest. *Id.* at 1154-55. Advances had to be fully repaid within five years of the date deliveries commenced, or the date it was determined that repayment would be in other than gas; and the delivery-commencement or alternative-determination date had to be within five years from the date of the advance. *Id.* at 1153-54. A refund to customers was required if an advance resulted in the finding of proven reserves, gas deliveries commenced, but no gas flowed to the advancing pipelines. *Id.* at 1554.

"the Commission plans to consider those amounts recorded in Account 166, Advance Payments for Gas, as rate base items, where found reasonable and appropriate." [35] Thus, properly recording an advance in Account 166 was a necessary, but not a sufficient, condition for inclusion in the rate base. The Commission also had to be satisfied that the advance was "reasonable and appropriate."

There has been no dispute that the advance payments at issue in these cases complied with the express conditions in the pertinent advance payment orders. What is

Order No. 499, *supra* note 4, extended the program for another two years and expanded its coverage to include Alaskan advances made under future contracts (previously only advances in the lower 48 states where eligible for rate base treatment). 50 FPC at 2115. Advances to independent producers resulting in the acquisition of a working interest were permissible, and economic benefits derived from working interest advances need not be credited against the pipeline's cost of service. *Id.* at 2114.

[35] Order No. 410, *supra* note 4, 44 FPC at 1144; Order No. 410-A, *supra* note 4, 45 FPC at 135 (by incorporation of Order No. 410); Order No. 441, *supra* note 4, 45 FPC at 1181; Order No. 465, *supra* note 4, 48 FPC at 1555, Order No. 499, *supra* note 4, 50 FPC at 2115.

contested is the Commission's discretion to interpret and administer the "reasonable and appropriate" guideline.

Two orders govern the advance payments in these cases. Order No. 465, issued December 20, 1972, governs advance payment contacts made during 1973. It contains an unelaborated statement of the reasonable and appropriate standard.[36] On December 28, 1973, the Commission issued Order No. 499, which governs advance payment contracts made during 1974-75. In that order, responding to public comments raising the critical timing issue, the Commission emphasized the applicability of the "reasonable and appropriate" standard to that issue. It did not adopt a strict timing rule, but instead stated that as a "general policy" advances must be appropriately expended by the producer within a "reasonable time." [37]

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[36] The Order provided: "Consistent with the amendments to Section 154.63 of the Regulations under the Natural Gas Act adopted herein, the Commission plans to consider those amounts allowed in Account 166, as rate base items, where found reasonable and appropriate." Order No. 465, *supra* note 4, 48 FPC at 1555.

[37] 50 FPC 2111, 2115 (1973):

> [A]s a general policy we shall not consider amounts advanced to be "reasonable and appropriate" for inclusion in rate base where such amounts are in excess of costs for exploration, development and production incurred by the producer within a reasonable time from the date such amounts advanced are included in the pipeline's rate base.

The Commission declined to formulate specific timing standards, determining instead to "examine each advance on a case by case basis." Accounting and Rate Treatment of Advances Included in Account No. 166, Advance for Gas Exploration, Development and Production, Docket No. RM74-4, Order Denying Rehearing of Order No. 499, 51 FPC 818, 819 (1974).

Huge sums in extended front-end advances were transferred to producers under contracts subject to Order No. 465. Despite the Commission's signal in Order No. 499 that it intended to focus on the critical timing requirement, the flood did not abate.[38]

D. *The Administrative Proceedings*

The administrative proceedings commenced with separate filings by petitioners for jurisdictional rate increases pursuant to section 4 of the Natural Gas Act.[39] Each filing was initially suspended, then became effective subject to refund.[40]

In the ensuing hearings the pipelines proposed that all advance payments made during the test period that complied with the express conditions of the relevant ad-

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[38] A report prepared on the basis of Commission files calculated that a total of $5.5 billion had been committed in advance payments as of February 1, 1976. Of that total it would appear that little more than 1% was advanced on a 30-day line-of-credit basis. INGAA Br. in No. 77-1496, *et al.* at 5 n.3; JA in No. 77-1496, *et al.* at 370. Of this total, more than $4.2 billion in front-end advance payments were reportedly committed between August, 1973 and February, 1976. JA in No. 77-1496 *et al.* at 370.

[39] 15 U.S.C. 717c (1976).

[40] Filing by Tennessee Gas Pipeline Co. (No. 77-1496 *et al.*) occurred on June 15, 1973, was accepted and suspended on August 1, and became effective subject to refund on January 1, 1974. JA in No. 77-1496 *et al.* at 321.

Transcontinental Gas Pipeline Corp. (No. 77-1212) made its pertinent filing on July 16, 1974. It was accepted and suspended by the Commission on Aug. 31, 1974, with the rates becoming effective subject to refund on Feb. 1, 1975. JA in No. 77-1712 at 165-66.

Michigan Wisconsin Pipeline Co. (No. 77-1719) filed for its rate increase on November 15, 1974. The rates became effective subject to refund on January 1, 1975. JA in No. 77-1719 at 104.

vance payment order should be included in the rate base. The Commission Staff argued that a reasonable timing element was inherent in the reasonable and appropriate standard and that the payment of advances could only be justified as necessary to provide producers a line of credit for current obligations. The Staff relied on the testimony of Robert H. Benna, who stated in part: [41]

> Based on my experience with Shell, I understand that producers are normally allowed 30 days from the date of billing to pay for contract work and materials. Thus, from the producers' standpoint, receipt of an advance one month prior to the date the related payment is due should allow ample time to pay the bill. The important factor, to the producer, is that he has a commitment by a financially stable pipeline to make advances in amounts and at the time necessary to cover exploration and development costs.

In the Staff's view, an advance was not reasonable and appropriate for inclusion in the rate base unless it was appropriately expended by the producer within 30 days of receipt. It was argued that the pipelines' stockholders, rather than their rate payers, should bear the carrying charges on front-end advances paid more than 30 days prior to their expenditure. Adapting this standard to the test-period methodology employed in rate making, the Staff proposed to disallow inclusion of extended front-end advance payments made during the test period but not appropriately expended within 30 days of its close.[42] The Staff would have allowed an

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[41] JA in No. 77-1712 at 64; JA in No. 77-1719 at 42-43; *see* JA in No. 77-1496 *et al.* at 6-7.

[42] JA in No. 77-1496 *et al.* at 309; JA in No. 77-1712 at 145-46; JA in No. 77-1719 at 108-11. It may be noted that this approach allowed certain advances to be included in rate base even if they were expended more than 30 days after

exception to this rule when it was demonstrated that a financial savings to the rate payer would result from the terms of a particular advance payment contract that outweighed the added cost of deviation from the 30-day rule.[43]

In response, the pipelines submitted extensive evidence of the competitive circumstances obtaining during the period in which the challenged advance payments were made. The pipelines argued that, in this environment, refusal to bid competitively for gas reserves by offering extended front-end advances would have left any hesitant pipeline without gas to meet its commitments, and that such a refusal would have been irresponsible in light of the pipeline's obligations to its customers.[44] Thus, it

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receipt. Though an advance made on the last day of a one year test period would have to have been expended within 30 days to qualify, advances made on the first day of that test period would qualify if expended anytime within the subsequent 13 months. Thus it might be argued that the effective timing reqirement (i.e., the average permissible front-end lag time) was considerably in excess of 30 days.

[43] JA in No. 77-1712 at 145; JA in No. 77-1719 at 116.

[44] *See* Opinion No. 769, Tennessee Gas Pipeline Company, Docket No. RP73-113, Opinion and Order Affirming in Part and Reversing in Part Initial Decision Establishing Just and Reasonable Pipeline Rates (July 9, 1976) (hereafter cited as "Opinion No. 769") (opinion of Commissioner Holloman, dissenting at 2) ("A pipeline such as Tennessee faced with this competitive climate would be remiss in its attempts to attach new supplies of gas on behalf of itself and its customers if it did not use this tool to enter into new gas supply contracts.") JA in No. 77-1496, *et al.* at 359; Opinion No. 769-A, note 32 *supra* (opinion of Commissioner Holloman, dissenting, at 1) ("For the plain fact is this program was thrust upon the pipeline companies, leaving them little choice but to negotiate for these arrangements or abandon the field to competing pipelines. Obviously, considered in the context of growing curtailments and deteriorating gas supply, the

was argued, an advance made in good faith response to competitive conditions was both reasonable and appropriate and should be fully included in the rate base.

The administrative law judges in the proceeding before us, while diverging somewhat in particular results, were congruent with each other in critical aspects.[45]

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latter course would have evidenced a willful disregard of Tennessee's responsibilities to its customers bordering on negligence."), JA in No. 77-1496 *et al.* at 406.

[45] Tennessee sought inclusion in rate base of nearly $197 million in advance payments to domestic producers, all governed by Order No. 465. JA in No. 77-1496 *et al.* at 313. The administrative law judge rejected Staff's 30-day rule as "unduly restricted and arbitrary." *Id.* at 311. In general, the pipeline's unchallenged good faith and business judgment was found to qualify advances as reasonable and appropriate. *Id.* at 310-11. However, the ALJ perceived an important difference with respect to $59 million of the total, comprising advances to affiliated producers. He found that these advances did not constitute an "arm's length transaction" since the unearmarked affiliate funds were advanced near the close of the test period and were available for uses unrelated to gas development. Approximately $28 million in unexpended intracorporate domestic advances were excluded from rate base. *Id.* at 314-15.

Transco's advances, totaling approximately $15 million, were governed in part by Order No. 465 and in part by Order No. 499. The pipelines' business judgment rule was accepted with respect to the Order No. 465 advances. JA in No. 77-1712 at 147. However, the ALJ viewed the articulation in Order No. 499 of a reasonable timing requirement as a sharp change in Commission policy. All Order No. 499 advances not expended at the close of the test period were excluded from rate base. *Id.* at 152-54.

Approximately $11.5 million in advance payments, governed by Order No. 499, are involved in the Michigan-Wisconsin proceeding. The ALJ found that all the front-end advances, including those made to an affiliated producer, satisfied the reasonable timing requirement even though they did not comply with Staff's 30-day rule. JA in No. 77-1719 at 112-14.

Each was receptive to the competitive conditions justification proffered by the pipelines. Each perceived the express mention in Order No. 499 of the timing requirement as a shift in Commission policy. By and large, each rejected the Staff's 30-day rule.

The Commission overruled the initial decisions, adopting the Staff's position that a reasonable timing requirement was inherent in the reasonable and appropriate standard of both Order No. 465 and Order No. 499. In its view, the advance payment program was designed to benefit rate payers by providing capital to finance exploration and development of additional gas supplies and to expedite development of existing reserves. It was not intended to provide a license for pipelines to bid against each other for available gas. The Commission concluded that there was no inherent justification in terms of the purposes of the program for advances made prior to the time they were reasonably required to facilitate qualifying producer expenditures. While these extended front-end advances provided a benefit to producers, no public service benefit could be discerned. In the Commission's view, only one consideration was relevant in determining whether a timing relationship satisfied the reasonable and appropriate standard: the financial requirements of the transaction, *i.e.*, the lag time required to allow a smooth transfer and expenditure of funds. The Commission regarded the Staff's 30-day line-of-credit rule as a well-pleaded presumption, subject to rebuttal, as to producer needs and pipeline abilities. Since there had been no showing by the pipelines that producers required funds more than 30 days prior to appropriate expenditure, nor that pipelines needed more time to finance advances, the Staff's rule was applied to determine inclusion in the rate base.[46] The Commission

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[46] Opinion No. 769, *supra* note 44, at 29-34, JA in No. 77-1496, *et al.*, at 348-51; Opinion No. 769-A, *supra* note 32, at

stated: [47]

> [W]hile we do not find that a maximum time lag of thirty days between advance and expenditure is necessarily the only reasonable and appropriate standard, it was well pleaded and completely unrebutted. . . .

The Commission adopted the Staff's proposal that any advances failing to satisfy the 30-day test would be included in rate base only if the terms of the particular advance payment contract would "save the ratepayer more in advance payment carrying charges than would be saved by insisting upon Staff's 30 day installment rule." [48] The Commission did not consider that its express reference to the timing requirement in Order No. 499 represented a dramatic shift in policy from its earlier orders. Rather, the reference merely highlighted

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4-10, JA in No. 77-1496 *et al.* at 395-401; Opinion No. 801 Transcontinental Gas Pipe Line Corp., Docket Nos. RP74-48 & RP75-3, Opinion and Order Affirming in Part and Reversing Initial Decision on Reserved Issues and Establishing Just and Reasonable Pipeline Rates 21-23 (May 31, 1977) [hereafter cited as "Opinion No. 801"], JA in No. 77-1212 at 185-87; Michigan Wisconsin Pipe Line Co., Docket No. CP70-22, *et al.*, Order Reversing Initial Decision 2-4 (June 3, 1977) [hereafter cited as "Michigan-Wisconsin Order"], JA in No. 77-1719 at 116-20. The Commission declined to differentiate between advances to affiliated and to non-affiliated producers, thus differing from the reasoning of the ALJ in the Tennessee proceeding. But the same result was achieved—exclusion of unexpended intracorporate advances from the rate base—on the basis of the 30-day standard.

[47] Opinion No. 769-A, *supra* note 32, at 5, JA in No. 77-1496, *et al.* at 396; Michigan-Wisconsin Order, *supra* note 46, at 4, JA in No. 77-1719 at 119.

[48] Opinion No. 801, *supra* note 46, at 22, JA in No. 77-1712 at 186; *see* Opinion No. 769, *supra* note 44, at 32, JA in No. 77-1496, *et al.* at 351; Michigan-Wisconsin Order, *supra* note 46 at 3, JA in No. 77-1719 at 118.

one element of the reasonable and appropriate standard. Thus, the same criteria were applied to both Order No. 465 and Order No. 499 advances.

The net effect of the Commission's advance payment determinations was the temporary exclusion from the rate base of advances not satisfying the timing requirement. It is important to note that this was a deferral, not a disqualification. Subsequent filings for rate increases would entail new test periods; ultimately, when the expenditure was in fact made during a test period or within 30 days after its close, the deferred advances would be included in the appropriate rate base. This deferral aspect must be distinguished from outright disqualification resulting when advances failed to satisfy one or more of the express conditions stated in the advance payment orders. Nevertheless, substantial sums were involved and deferral has resulted in considerable losses for the pipelines' stockholders.

E. *Interpretation of the Advance Payment Orders*

The pipelines assert that the advance payment orders contemplated the use of extended front-end advance payments as a mode of competition for available supplies of gas. From this it is argued that the Commission's current interpretation constitutes retroactive rule making. The pipelines rely principally on various excerpts from the text of the orders, and draw additional support from language in previous administrative decisions. Moreover, it is asserted that to the extent the Commission's current interpretation might at one time have been a reasonable and legally supportable construction, that approach has been foreclosed by the Commission's repeated renewal of the program without appropriate modification in the face of actual and constructive notice that extended front-end advances had become a term of trade. The express mention of a reasonable timing standard in

Order No. 499 is viewed as an inadequate reaction to a crying need. Indeed, the generality of the Commission's response to specific comments is cast as further evidence that the Commission did not intend at the time to curtail extended front-end advances. Finally, as to the Commission's use of Staff's 30-day rule as a presumption subject to rebuttal, petitioners challenge its evidentiary basis, and more fundamentally its premise that the only factor relevant to application of the reasonable and appropriate standard was the financial requirements of the transaction.

The essence of petitioner's arguments is this: multiple factors encouraged extended front-end advances, and no specific Commission direction restricted their use. Asserting that each pipeline's good faith business judgment should prevail over the Commission's present interpretation, petitioners propose this clear-cut rule: "the sole test for determining whether the advance payments made under these orders were to be included in rate base as 'reasonable and appropriate' [should have been] whether they were made in order to obtain commitments for additional gas supplies." [49]

We find that petitioners' arguments in support of their interpretation are undercut by consideration of the character of the advance payment program as an experimental departure from well accepted and understood principles of regulatory law. The Commission has correctly construed the underlying purposes of the program as it was understood by this court in *PSC (Advance Payments) I & II* and has not abused its discretion in discerning a reasonable timing requirement and in rejecting petitioners' "business judgment rule" as the "sole

[49] Tennessee Br. in No. 77-1496, *et al.* at 15 (emphasis deleted).

test" for the program's administration.[50] Completely separate, however, is the question whether the Commission, in choosing a manner of administering the reasonable timing requirement, gave due consideration to all pertinent factors. As discussed in section I-F *infra*, we conclude that it did not, and remand. But first we turn to those considerations that support rejection of petitioners' business judgment rule.

1. *Petitioners have the burden of demonstrating an affirmative authorization for extended front-end advances.* In *Smyth v. Ames*,[51] the Supreme Court articulated the guiding principle that "the basis of all calculations as to the reasonableness of rates to be charged by a [public utility] must be the fair value of the property *being used by it for the convenience of the public.*" Although methods for determining values of rate base items have evolved since *Smyth v. Ames*,[52] the precept endures that an item may be included in a rate base only when it is

[50] Although we employ the term "business judgment rule" to characterize the pipelines' suggested approach, we do not intend to import the extensive jurisprudence that has developed in connection with use of the term as a standard for measuring the duty of corporate directors and other fiduciaries.

[51] 169 U.S. 466, 546 (1898) (emphasis supplied).

[52] *See* FPC v. Hope National Gas Co., 320 U.S. 591, 605 (1944); FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 599-608 (1942) (concurring opinion of Black, Douglas and Murphy, JJ.); Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122-24 (1939) (Frankfurter, J., concurring); McCart v. Indianapolis Water Co., 302 U.S. 419, 423-41 (1938) (Black, J., dissenting); Missouri *ex rel.* Southwestern Bell Tel. Co. v. Public Service Com'n., 262 U.S. 276, 289-312 (1923) (opinion of Brandeis, J.); City of Detroit v. Panhandle Eastern Pipe Line Co., 3 FPC 273, 278-80 (1942); Chicago District Electric Generating Corp., 2 FPC 412, 416-20 (1941).

"used and useful" in providing service. In other words, current rate payers should bear only legitimate costs of providing service to them. The FPC early adopted the "used and useful" standard and has not departed from it without careful consideration of the wisdom of requiring current rate payers to bear costs of providing future service.[53]

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[53] *E.g.*, Mississippi River Fuel Corp., 4 FPC 340, 344 (1945) ("It has been the general practice of this Commission to determine the rate base by ascertaining the net investment in the gas plant used and useful in rendering service, and adding a reasonable allowance for working capital."); Chicago District Electric Generating Corp., 2 FPC 412, 420 (1941). The "used and useful" standard was expressly incorporated into the depreciation provisions of section 9 of the Natural Gas Act, 15 U.S.C. § 717h (1976), which provide in part: "The Commission may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used and useful in the production, transportation or sale of natural gas."

Compare Cities Service Gas Co., 3 FPC 459, 490 (1943) ("While a strict interpretation of rate making principles might require no allowance for return and depreciation on the Hugoton [pipeline] project until it is completed and in service, we believe that, because of the urgent necessity for relieving the gas transportation shortage during the war emergency, it is in the public interest presently to make such an allowance in connection with the interim reduction of rates ordered in this proceeding."); General Policy and Interpretations, Inclusion of Construction Work in Progress in Rate Base, 41 Fed. Reg. 51392, 51393 (1976) ("The question of the proper treatment for ratemaking purposes of capital expenditures which have not yet been placed in service is one which is subject to a play of conflicting principles. On the one hand, public utility regulation has generally adhered to the principle that a rate base should only include items which are 'used and useful.' On the other hand, regulation has also always recognized that the expense of financing construction to serve customers is itself a legitimate expense which must ultimately be borne by the ratepayers."); Order

One such departure was the advance payment program. At the very least it contemplated that current rate payers would shoulder the costs (*i.e.*, the financing charges) of qualifying advance payments. This was intended to expedite the development of additional gas reserves by providing supplemental sources of capital, which would be used to provide service for future rate payers. Such a modification of the "used and useful" principle was thought justified in view of the discouraging supply forecasts and the general correspondence between classes of current and future rate payers. Consumers would eventually have to bear the costs of developing needed gas supplies. In theory, the advance payment program promised to provide that gas at the lowest ultimate cost.[54]

The Commission has taken the position that any departure from such a well-rooted regulatory principle must be affirmatively authorized and that an authorized departure must be presumed limited to its express terms. We agree with the analysis that agency silence in these circumstances must be construed to mean that traditional principles retain their vitality.[55] We are not so clear that authorization for a departure from settled principles must be expressly set forth in an order (as contrasted with what is fairly discernible as the intent

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No. 566, Changes in Accounting and Rate Treatment for Research, Development and Demonstration Expenditures, Docket No. RM76-12 (June 3, 1977). Regulations permitting rate-base treatment of R & D expenditures, with certain qualifications, are codified at 18 CFR 201(103) (1978).

[54] *PSC (Advance Payments) I*, *supra* note 3, 151 U.S.App. D.C. at 316, 467 F.2d at 370.

[55] *See* NLRB v. Majestic Weaving Co., 355 F.2d 854, 860 (2d Cir. 1966); NLRB v. International Bhd. of Teamsters, 225 F.2d 343, 348 (8th Cir. 1955). *See* Standard Oil Co. v. Dept. of Energy, No. 6-13, slip op. at 20-56 (Temp. Emer. Ct. App. 12/13/78) (reaching a different result where there existed no previously well-settled rule).

of an order), but it must be established with reference to the order.

This conclusion allows us to by-pass petitioners' factual assertions that, during the pendency of the program, the Commission had actual and constructive notice that it was widely understood within the industry to be acquiescing in extended front-end advances. It is urged that the Commission's failure expressly to restrict extended front-end advances gave such payments an affirmative blessing, or—what is the same thing—estops the Commission from now asserting an interpretation contrary to that held by the pipelines. We accept *arguendo* petitioners' factual assertions of notice, and reject their proffered conclusion. Though a belief that the agency was cognizant of widespread employment of extended front-end advances may have further encouraged their use, the Commission's inaction cannot be construed to change existing law where the Commission resists such a change and has given no indication that it intended a wholesale abandonment of traditional principles. Any modification of traditional principles broad enough to permit extended front-end advances must be derived from the advance payment orders themselves, not from Commission inaction. Further, since the Commission relies on well-established principles of public utility law, it is not sufficient for petitioners to come forward with some conceivable interpretation of language in the advance payment orders that supports their view. At the very least, the burden must fall on petitioners to demonstrate that a preponderance of the interpretative evidence is favorable to their position.

2. *The program was intended to provide additional sources of capital to expedite development of gas supplies, not to give license for competition among pipelines.* Petitioners attempt to carry their burden of showing an affirmative authorization for extended front-end advances

by citing specialized provisions of the advance payment orders, which they construe to support their position. The first problem is that the cited passages, often less than clear, are subject to conflicting interpretations.[56] But a more fundamental difficulty with petitioners' approach is the premise that the underlying purposes of the program

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[56] For example, petitioners place substantial reliance on the statement in Order No. 441, *supra* note 4, that: "Advances may be recorded in Account 166 and *shall* be included in rate base where such payments are reasonable, necessary and appropriate in order to contract for gas supplies by agreement executed not later than December 31, 1972." 46 FPC at 1180 (emphasis supplied). Petitioners focus our attention on the facially directory langauge. It may be noted first that following this statement, the order iterates, "the Commission plans to consider those amounts recorded in Account 166, Advance Payments for Gas, as rate base items, where found reasonable and appropriate." *Id.* at 1181. An harmonious construction of these two sentences is that need "to contract for gas supplies" is a necessary, but not a sufficient condition for inclusion in rate base. We may note secondly that the key ingredient added to the order by the relied-upon sentence is specification of the order's termination date as December 31, 1972. Concentration on the sentence's primary purpose may have caused the Commission to overlook careless drafting. Insofar as petitioners' argument is premised on a justifiable reliance on the directory language, it is undercut by the Commission's paraphrase of the critical sentence in the Order of Clarification and Denial of Rehearing or Modification, 47 FPC 57, 58 (1972):

> Tennessee is uncertain as to whether a return will be allowed on the unamortized balances of non-recoverable advances. It is our stated position in the fourth paragraph of page 1180 of Order No. 441, that advances recorded in Account 166 *may* be included in rate base where such payments are reasonable, necessary and appropriate in order to contract for gas supplies by agreement executed not later than December 31, 1972. There is no provision for the inclusion in rate base of amounts that must be eliminated from Account 166.

(Emphasis supplied.)

were sufficiently ambiguous to admit of an interpretation favorable to extended front-end advances. We find overwhelming the Commission's evidence as to the purposes of the program, as intended by the Commission and as understood by this court in *PSC (Advanced Payments) I*. Thus we need not pause to consider in depth the particulars of petitioners' references (and the Commission's strenuous rebuttals) but may proceed to consider the evidence supporting the Commission's narrower view.

In the introductory paragraphs to Order No. 441, the advance payment order conditionally approved in *PSC (Advance Payments) I*, the Commission stated: [57]

> In our area rate opinions for *Southern Louisiana* and *Texas Gulf Coast* (Opinion Nos. 598, 46 FPC 86, and 595, 45 FPC 674), we recognized that it is the function of a just and reasonable rate for independent producers to elicit requisite gas supply, and that costs, in economic terms, reflects the required level of capital formation to elicit that level. In other words, the just and reasonable area rate in these recent opinions did not consider "non-cost" items. Having acknowledged, as we do, that provisions for special rate treatment of advance payments by pipelines have been justified in the past on the basis of providing additional incentives in this experimental undertaking, we nevertheless seek to avoid separate, non-price incentives as much as possible.
>
> A critical shortage of gas exists in the United States; capital formation for gas development is difficult. The objectives of providing capital to accelerate the addition of new gas supplies supports our continuation for the limited period of the rate treatment of advance payments provided herein. We recognize that the just and reasonable area rates

[57] Order No. 441, *supra* note 4, 46 FPC at 1179-80.

> for independent producers will hopefully alleviate this gas supply shortage over the long-run; however, for the immediate term, (namely through 1972) our advance payments policy has been designed to increase directly the funds available for the necessary exploration and developmental effort. It is our intention that rate base treatments for advances included in Account 166 be terminated for advances resulting from contracts executed after December 31, 1972, unless otherwise ordered.

The Commission's starting point was its recognition of the role of just and reasonable area rates for producers in "elicit[ing] requisite gas supply." For the long-run, the articulated policy was to incorporate in the certificated rate all required incentives to assure requisite supply; "non-price incentives" were to be avoided "as much as possible." Contrary to this long-term policy, advance payments embodied a "non-price incentive" in the "bonus" inherent in the interest-free loan of capital. Nevertheless, since the Commission recognized that a "critical shortage of gas exist[ed]" and "capital formation for gas development was difficult," the "objective of providing capital to accelerate the addition of new gas supplies" justified continuation "for the immediate term" of a policy "designed to increase directly the funds available for the necessary exploration and developmental effort." It was apparent on the face of the order that the purpose of an advance payment was to provide "reasonable and appropriate" developmental capital for "qualifying expenditures." Yet, the pipelines argue that the orders approved all extended front-end advances, contary to the Commission's view that for the extended period between receipt and expenditure many of these advances made no such contribution of developmental capital while providing producers with a non-price incentive of the type the program explicitly sought to avoid "as much as possible." In the face of such a clear ex-

pression of limited purpose, we find untenable the argument of the pipelines for carte blanche authority to make advances.

One of petitioners' arguments that figures prominently in any defense of the pipelines' behavior asserts that the advance payment program contemplated competition among pipelines for available gas through the use of extended front-end advance payments, which would effectively raise the price of natural gas and thus inevitably contribute, in an indirect way, to the alleviation of the natural gas shortage. The fatal weakness in this argument is that it confuses an incentive with a justification. Certainly the Commission contemplated that the prospect of obtaining additional gas reserves for an individual gas distribution system would encourage a pipeline to offer advance payments.[58] But the mere fact that an advance payment made good business sense to the advancing pipeline was not alone sufficient to authorize its use. Advance payments were not an end in themselves. They were legitimate only insofar as and to the extent that they provided producers with a source of developmental capital for use in qualifying expenditures. In the passage from Order No. 441 quoted above, the stimulating effect on gas supply of the price-incentive aspect of advance payments was expressly *excluded* by the Commission as an objective of the advance payment program; rather, the price-incentive aspect was tolerated as a necessary and subsidiary adjunct to the capital-formation objective.

The conclusion that the Commission had no intention of encouraging internecine bidding among gas-starved pipelines is fortified by the pervasive tone of the advance payment orders, exemplified by the above-quoted passage, that the overall goal in both the long-run and the

[58] *See* note 8 *supra*.

immediate-term was to elicit requisite gas supply for the nation *as a whole*, not for any particular pipeline system at the expense of others.

In another provision of Order No. 441, the Commission showed a particularized concern that advances should not be used for competitive purposes but rather should be cost-justified in terms of the consumer benefit derived from furtherance of the program's objectives:[59]

> Our review of the various comments and available data has persuaded us that advances for exploration and lease acquisition have not [been] shown to be an effective vehicle *for stimulating the widespread participation in natural gas production for which their encouragement was intended.* Moreover, there is some indication that the availability of advances for such purposes by creating competition among pipelines to make such advances may be having the effect of increasing the amounts expended on lease acquisition without a proportionate improvement in gas supply.

The Commission excluded from the category of "qualifying expenditures" advance payments for exploration and lease acquisition since they could be identified as an entire category that did not further the justifying objectives of the program, but were instead fostering undesirable competition among pipelines without an offsetting consumer benefit. When this court affirmed the program in *PSC (Advanced Payments) I*, we highlighted this adjustment as an example of the Commission's flexibility and willingness to modify the program, which we considered a prerequisite to sound administration.[60]

[59] Order No. 441, *supra* note 4, 46 FPC at 1180 (emphasis supplied).

[60] *PSC (Advance Payments) I*, *supra* note 3, 151 U.S.App. D.C. at 313, 467 F.2d at 367.

In *PSC (Advance Payments) I*, we unambiguously understood the program's objective to be the creation of an additional source of capital to facilitate the natural gas development and production necessary to alleviate the gas shortage. In one illustrative passage, we noted:[61]

> The rationale behind this decision is that the advance payments will help to give the gas producers the necessary investment capital to finance the development and production needed to alleviate the gas shortage, and the pipelines will be encouraged to make such advance payments if they are allowed to include the payments in their rate base, thus virtually simultaneously shifting the cost of the advance payments to the pipelines' customers, the natural gas consumers.

There was no hint in *PSC (Advance Payments) I* that a justifying objective of the program was the encouragement of competition among pipelines for scarce supplies of gas. On the contrary, by consistently referring to "producers," "pipelines" and "consumers" throughout the opinion, we evidenced our conviction that the revelant interests were nationwide in scope, not those of any particular pipeline or its customers.

It is a crucial aspect of this case, refuting the pipelines' basic retroactive rule making contention, that the limited purposes of the advance payment program were unambiguously articulated, in both Order No. 441 and in the affirming opinion of this court, well prior to the date of any advance payment contract involved in these cases.

In *PSC (Advance Payments) I* we had made clear that continued approval of the program was dependent on the Commission's ongoing modification and evaluation to as-

[61] *Id.* at 309, 467 F.2d at 363. *See also id.* at 317, 467 F.2d at 371 (on petition for rehearing).

sure that the program was accomplishing its ultimate purposes—alleviation of the gas shortage—at an acceptable cost to the natural gas consumer. This process was undertaken in both Order No. 465 and Order No. 499. In the opening sentence of each, the Commission stated that the focus of its inquiry was "to determine whether the advance payment program [was] stimulating activity toward increasing the supply of natural gas sufficiently to justify the extension of rate base treatment of advances." [62] In Order No. 465 the Commission concluded: "in view of our analysis of all the responses . . . and our review of the program of advances in general, we find that rate base treatment of advances to producers has 'represented a justifiable experiment in the continuing search for solutions to our nation's critical shortage of natural gas.'" [Quoting from *PSC (Advance Payments) I*] [63] In Order No. 499 the Commission stated: "review of the data . . . indicates that the advance payment program has continued to meet its objectives of bringing additional gas supplies into the interstate market at an acceptable cost to the nation's gas consumers," and "that pipeline advances have continued to accelerate the capital formation which led to the exploration, development and dedication of 10.27 Tcf of proven reserves of natural gas as well as 9.57 Tcf of potential reserves of natural gas to the interstate market." [64] Neither Order No. 465 nor Order No. 499 severed the tie between the objective of capital formation and the authorized use of advance payments. Each Order continued to assess the program in terms of nationwide gas supply, not improvement for some pipeline systems at the

[62] Order No. 465, *supra* note 4, 48 FPC at 1550; Order No. 499, *supra* note 4, 50 FPC at 2111.

[63] 48 FPC at 1553.

[64] 50 FPC at 2112-13.

expense of others. Again, there was direct evidence that competition among pipelines was not a desirable nor intended effect of the program.[65] Although we found the Commission's review of the data inadequate in *PSC (Advance Payments) II*, we found no inconsistency of purpose in the Commission's orders and reiterated our understanding of the program as expressed in *PSC (Advance Payments) I* and in the previous orders.[66]

The Commission consistently referred to the purpose of capital formation to accelerate improvement in overall gas supply as the purpose of the program and never put forward the purpose of facilitating for its own sake the enhancement of producer prices through competition among pipelines for available gas supplies. Had the Commission advocated such an objective, we discern no basis on which we would have approved it as permissible under the Natural Gas Act.

3. *Legal infirmity of a program approving all front-end advances.* The Natural Gas Act requires the Commission to anchor its regulation of producers in the maintenance of just and reasonable rates. In *Texaco*,[67] which issued at a time when the strain of natural gas shortage

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[65] In Order No. 465, *supra* note 4, the Commission stated:

> It is clear then that advances for exploration and lease acquisition have resulted in significant production activity. However, the comments indicate that advances for lease acquisition may have been a contributing factor in bidding up of the price of leases. Therefore we shall henceforth allow advances for exploration in rate base while continuing to exclude advances for lease acquisition from rate base.

48 FPC at 1554 (1972).

[66] *PSC (Advance Payments) II*, *supra* note 3, 167 U.S.App. D.C. at 103-04, 111-13, 511 F.2d at 341-42, 349-51.

[67] FPC v. Texaco Inc., 417 U.S. 380 (1974).

was acute, the Supreme Court held that the Commission had acted impermissibly in exempting small producers from direct rate regulation and rejected as inadequate the Commission's contention that it was sufficient to regulate small producers indirectly, by reason of the consequences of regulation of pipelines and of large producers. Indirect regulation was permissible, but only when and if the Commission developed safeguards to ensure that the rates paid by pipelines, and ultimately borne by consumers, remained just and reasonable.[68]

In *Consumer Federation of America v. FPC*,[69] we disapproved a program in which the Commission attempted to authorize competitive bidding for needed gas supplies by pipelines experiencing critical short-term supply difficulties. That program granted producers 180-day exemptions from rate limitations and permitted them to enter into contracts with eligible pipelines without risk of refund. The order provided that gas costs "shown to have been required by the public interest" were to be passed on to consumers.[70] We invalidated the program, even though it was proffered as an experiment responding to a supply crisis, since it failed to provide adequate assurance that just and reasonable rates would be maintained. We concluded:[71]

> [T]he Commission has exceeded its authority under the Act. In essence, it has attempted to remedy the shortfall of supply in the interstate market by au-

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[68] *Id.* at 401.

[69] 169 U.S.App.D.C. 116, 515 F.2d 347 (1975).

[70] Order No. 491-B, 50 FPC 1463, 1470 (1973). The program reviewed in *Consumer Federation* was governed by Order No. 491, 50 FPC 742 (1973); Order No. 491-A, 50 FPC 848 (1973); Order No. 491-B, *supra;* and Order No. 491-C, 50 FPC 1634 (1973).

[71] 169 U.S.App.D.C. at 129, 515 F.2d at 360, *quoting PSC (Advance Payments) I*, *supra* note 3, 167 U.S.App.D.C. at 116, 511 F.2d at 354.

> thorizing a supplemental injection of large quantities of gas through sales freed from the constraints of meaningful regulation. We reject the FPC's claim that § 7(c) [of the National Gas Act] supports this substantial, partial deregulation, and find that the Commission has neglected its rate control responsibilities under the Act. Congress has yet to embrace proposals for deregulation of new gas supplies. Until it acts to alter the present "system of regulation by an agency subject to court review, the courts may not abandon their responsibility by acquiescing in a charade or a rubber stamping of nonregulation in agency trappings."

To adopt petitioners' contention, which would validate any "timing" arrangement that a pipeline found justified as a matter of business judgment were it to compete successfully for gas supply in a shortage crisis, would be nothing more nor less than acceptance of a deregulatory approach, a ruling that cannot be reconciled with the teaching of *Texaco* and *Consumer Federation*. A producer receiving an extended front-end advance, to use without restriction for a significant period prior to expenditure, is in effect given a sum of money. There is no meaningful distinction between receipt of unrestricted funds for a period and receipt of a sum equivalent to the "return" (at a minimum, interest) procurable from use of the funds. In both circumstances producers will be compensated in excess of certificated rates. The business-judgment rule would permit pure competitive bidding by pipelines using the device of extended front-end advance payments.

Had the Commission articulated the approach now advanced by the petitioners as an interpretation, we would have disapproved it as an abdication of the agency's regulatory responsibilities. This is not to say that the deployment of funds must be instantaneous. What is

inappropriate is unrestricted transfer for more than a reasonable period—a concept to which we shall return.

Any permission to transfer advances prior to gas delivery (even as to funds used immediately or in a reasonable time for qualifying developmental expenditures) entailed some variance from the previous situation, in terms of benefit to producer and of cost to pipeline and customer. However, the ultimate cost to the consumer was projected to remain within the just and reasonable range because of the compensating benefit of expedited gas development, and the maintenance of restrictions relating the cost to the benefit.[72] This justification, and these safeguards, were lacking as to the extended front-end advances made without restriction other than the competitive "business-judgment rule."

4. *Claim of retroactive rule making.* The foregoing analysis undercuts petitioners' contention that a reasonable timing requirement amounted to retroactive rule making. The pipelines had fair notice both of traditional regulatory principles and that the advance payment program exception was put forward and affirmed on a basis that did not encompass the departure asserted by petitioners.

In *Natural Gas Pipeline Co. v. FERC*,[73] the Seventh Circuit recently ruled that the Commission's interpretation of the reasonable and appropriate standard to impose a relatively inflexible "30-day rule" constituted im-

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[72] These restrictions include the maximum allowable payback period (*see* note 34 *supra*), economic motivations for producers to proceed expeditiously with development once advances have been "sunk" in qualifying expenditures, and the continued supervision of all aspects of timing and amount of advance payments under the reasonable and appropriate standard.

[73] 590 F.2d 664 (7th Cir. 1979).

permissible retroactive rule making. It viewed the case as falling within a doctrine, articulated in *Bell Aerospace Co. v. NLRB*,[74] whereby an agency's broad discretion to announce policy in adjudication is subject to an exception in a case of severe impact and justifiable reliance on contrary agency pronouncements.[75] It stated:[76]

> The consequences to the appellant of denying rate base treatment to the advances are very severe. It would mean the imposition of a large liability with regard to the advances in the present case. Furthermore, the appellant's entering into these agreements, under these terms, was in reliance upon the prior orders of the Commission, and the policies reflected in those orders, specifically the policies encouraging the advance payment program, with few restrictions, and the promulgation of a flexible standard with regard to the advance-expenditure time relationship. We believe that the aforementioned facts require that the Commission's discretion to proceed by adjudication as opposed to by rulemaking be restricted so as to prevent the imposition of a "30 day rule" in this proceeding.

We differ from the Seventh Circuit in that, in our appraisal, the Commission's current interpretation of the limited purpose of the advance payment orders does not reverse a policy that had been the subject of reasonable reliance.

The Commission's rulings on appeal are rooted in basic principles of regulation and in petitioners' notice of the limited purpose of the advance payment exception. We do

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[74] 416 U.S. 267 (1974).

[75] *Id.* at 295.

[76] 590 F.2d at 669.

not discern the substantial claim of justifiable reliance that is needed to invoke the *Bell Aerospace* exceptions.[77]

In support of its ruling the Seventh Circuit cited our decision in *Consumer Federation*:[78]

> While the factual pattern of *Consumer Federation of America, supra,* is not identical to the present case, the opinion does demonstrate an effort being made to protect the pipeline companies from the squeeze which results if the pipeline incurs expenses for emergency gas which is not refundable. A very similar type of problem to that discussed in *Consumer Federation of America, supra,* is present in this case. Through Order No. 499, and the four previous orders, the Commission encouraged a program of advances by interstate pipelines to producers to secure commitments of natural gas. Furth-

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[77] The limitations on permissible retroactivity may be discerned from SEC v. Chenery Corp., 332 U.S. 194 (1947), and NLRB v. Majestic Weaving Co., 355 F.2d 854 (2d Cir. 1966) (Friendly, J.). The relevant factors include the degree of retroactivity, the need for administrative flexibility, and the hardship on the affected parties. With respect to advance payments, the Commission has not changed an explicit past policy *(Majestic Weaving)* but rather has reaffirmed well-established regulatory principles. The need for flexibility is evident in a case, such as this, where "the agency may not have had sufficient experience with a particular problem to warrant rigidifying its tentative judgment into a hard and fast rule." *Chenery*, 332 U.S. at 202. The Commission specifically noted the need for a case-by-case determination of the timing question. *See* note 37 *supra*. Hardship to the pipelines is mitigated by two factors. First, the Commission merely has deferred rate-base treatment, not forever disqualified extended front-end advances from inclusion in rate base. Second, even during the deferral period, the pipelines have the assurance that their rates will remain at compensatory levels. FPC v. Texaco, 417 U.S. 380, 391-92 (1974); FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 585 (1942).

[78] 590 F.2d at 670.

ermore, inherent within the Commission's orders was an attitude of experimentation and flexibility as reflected in the "reasonable time" standard which the Commission chose to include in Order No. 499. Nevertheless, in electing to utilize a "reasonable time" standard, by itself, the Commission failed to furnish the pipelines with any sort of guidelines which might be followed in contracting with producers for commitments of gas reserves. Then after the agreements are entered into and the advances made, the Commission wants a "reasonable time" to be defined as "30 days", with the obvious effect of such action being that the pipeline would be forced to absorb huge costs which are not capable of being reflected in its rate base. To follow the course set forth by the Commission would be to contravene the policy expressed by the court in *Consumer Federation of America, supra.*

The Seventh Circuit's citation of our opinion in *Consumers Federation* is a subsidiary point in its approach, dependent on its major premise of justified reliance. In any event, we did not intend *Consumers Federation* to express a general solicitude for all pipelines caught in a "squeeze" to obtain gas. In that case there was a wholesale deregulation of producers, and we found that the indefinite indication that pipelines would be held to a "public interest" limit on prices paid was not enough to assure maintenance of just and reasonable rates. In the present case, there was a continuing regulation, not a deregulation, and the advance payment order that was judicially approved articulated a reasonable and appropriate standard which the Commission, and this court, find was not discarded, as to the matter of timing of payments, in favor of a competitive business judgment rule.

While we differ from the Seventh Circuit both on the issue of justifiable reliance and on the meaning of *Consumers Federation*, we agree with that court in its dis-

approval of the Commission's relatively rigid "30-day rule." We concur in its view that "inherent within the Commission's orders was an attitude of experimentation and flexibility," [79] which in turn involves flexibility in administration. We develop our views in the next section of this opinion, but interpolate at this point that the remand which we order can be implemented by the Commission with results that do not violate the remand by the Seventh Circuit.

F. *Improper FERC Administration of the Advance Payment Program*

We have concluded that the Commission acted within its discretion in rejecting both the pipelines' interpretation of the advance payment orders and their proposed competitive business judgment rule for administration of the "reasonable and appropriate" standard. We now turn to a consideration of the Commission's administration of the "reasonable timing requirement," which in light of the program's justifying objectives was implicit in the reasonable and appropriate standard.

We recognize the limited scope of our review function. Although a court may not supplant the Commission's well-reasoned judgments with those more nearly to its liking, it must assure itself that "the Commission has given reasoned consideration to each of the pertinent factors." *Permian Basin Area Rate Cases*, 390 U.S. 747, 792 (1968).

1. *Defining the reasonable timing requirement.* In evaluating the timing relationship between an advance payment and its qualifying expenditure, the Commission focused solely on the timing requirements of conventional financing transactions.[80] It relied on the testimony of its

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[79] *Id.*

[80] *See* text accompanying note 46 *supra.*

staff engineer Robert H. Benna set forth earlier in this opinion.[81] His testimony, based on his earlier employment by Shell, was submitted as evidence that producers could satisfactorily arrange for payment of contract and materials costs on the basis of a continuing commitment and specific payments thirty days in advance of due date. From this the Commission evolved a 30-day line-of-credit approach, which it established as a presumption subject to rebuttal. It found that in the cases before it the rule was unrebutted by evidence of financial inability on the part of either producer or pipeline to arrange for payments due under advance payment contracts to be transferred on a line-of-credit basis. We find the Commission's approach unduly restrictive in that it failed to take account of all factors relevant to the "reasonable timing" inquiry.

We agree with the Commission that its advance payment orders do not imply either a competitive business judgment rule as the sole standard for timing of advances, or authority for the extravagant costs of extended front-end advances not accompanied by reasonable controls on the timing of expenditures. However this does not mean that its orders disclosed a requirement that the pipelines adopt the "tight" timing practices of conventional financing transactions employed by producers like Shell in their arrangements with contractors. No strict line-of-credit requirement could fairly be implied from the terms of the advance payment orders. By so restricting the scope of its "reasonable timing" inquiry, the Commission failed to evaluate fully and fairly the reasonableness of the protective mechanisms adopted by particular pipelines to fulfill their obligation of vigilance in the consumers' interest.[82]

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[81] *See* text accompanying note 41 *supra*.

[82] Had the Commission considered all pertinent factors, we would not lightly overturn its result merely because of severe

The advance payment program was accepted by all concerned as an experimental and unconventional method of financing producer expenditures. The program embodied an important element of flexibility. This was a key feature both of our approval of the program in *PSC (Advance Payments) I*, and of our subsequent remand in *PSC (Advance Payments) II*. Nothing in the advance payment orders, not even in Order No. 499 with its express reasonable timing requirement, hinted that the pipelines were limited to line-of-credit or other conventional banking practices in the development of practical financing packages that would facilitate capital formation by producers while adequately protecting consumer interests, thus keeping advances within the confines of the program. Order No. 499 provided that as a general policy an advance should be appropriately expended within a reasonable time from "the date such amounts advanced are included in the pipeline's rate base." [83] The language of the order is instinct with latitude.

The Commission's failure to take into account the inherent flexibility of the advance payment program was the basis for our ruling in *United Gas Pipe Line Co. v. FPC*.[84] In that case, involving latitude of choice of financing methods, we vacated the Commission's summary re-

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hardship for pipeline investors. As recently as FERC v. Pennzoil Producing Co., 99 S.Ct. 765 (1979), the Supreme Court has suggested that the Commission's discretion to withhold relief from harsh application of familiar regulatory principles is not abused unless rate levels border on the confiscatory. *Id.* at 772. That case involved the Commission's equitable discretion, not the review of a determination, as in this case, of applicable legal standards arising in the context of an experimental, conditionally approved program.

[83] *See* note 37 *supra*.

[84] 179 U.S.App.D.C. 274, 551 F.2d 460 (1977).

jection of rate-base treatment for United's complex financing arrangement, which entailed an interest-reimbursement scheme rather than the lump-sum transfer of capital more typical of advance payment contracts. The arrangement contemplated that United would assist the producer to locate sources of developmental capital, and then reimburse the producer's financing costs. In our opinion for remand we noted that we found nothing in the advance payment orders precluding this method of facilitating capital formation.

In the pending case involving Transcontinental Gas Pipeline Corporation (Transco),[85] the advance payment contracts "provided for payment by Transco on January 10 and July 10 of each year of the estimated expenditures for the subsequent six months, with adjustments semi-annually and annually to reflect overexpenditures, or underexpenditures, respectively." [86] The Commission did not say one way or the other whether the pipeline acted reasonably in fashioning this procedure as a technique for controlling producer expenditures. Instead, it applied its line-of-credit rationale to exclude from rate base all advances not expended within 30 days of the close of the test period. It appears that Transco's approach of periodic accounting and adjustment, with a semi-annual review of expenditures, constituted a prima facie showing of an effort to tie payments to "qualifying expenditures." We agree with the position of the Public Service Commission of the State of New York, intervenor in the *Transco* proceeding, that in such a case "the shoe is on the other foot" and it is incumbent upon the Commission to articulate why this attempt to protect the

[85] No. 77-1712.

[86] Transco Br. in No. 77-1712 at 17-18.

consumers' interest falls outside the zone of reasonableness contemplated by the advance payment orders.[87]

We remand the cases before us for a more extensive and flexible inquiry by the Commission into the reasonableness of attempts to protect the rate payers from excessive costs. If it concludes that contracts such as those presented by Transco did provide for reasonable timing protections, the Commission would have latitude as a matter of equitable discretion to conclude that the kind of interval found reasonable in a case such as Transco's could be accepted as a general bench mark, even as to contracts that did not contain precisely the same provisions. On the other hand, based on the circumstances of a particular case, the Commission may determine that a much shorter timing interval was reasonable. For example, we note that in the proceeding involving Tennessee Gas Pipeline Co.,[88] Tennessee transferred $59 million in domestic advance payments to an affiliated producer. These advances were effected within the last 35 days of the test period, involved a mere bookeeping transfer without restrictions on the timing or nature of expenditures, and to the greater extent were not put to use in qualifying expenditures for many months.[89] The ALJ disallowed the unexpended portion of these advances because in his judgment they did not constitute an arm's length transaction. The Commission reached the same result on a different rationale, deferring rate-base treatment on the basis of the 30-day rule. On remand, the Commission may determine that such advances to affiliated producers present one example of unjustifiable misuse of the advance payment program.[90]

[87] PSC Br. in No. 77-1712 at 4.

[88] No. 77-1496 *et al.*

[89] JA in No. 77-1496 *et al.* at 313-14.

[90] We construe the pertinent advance payment orders as permitting advances to affiliated producers to be included in

It is evident that a broad range of financing practices were employed under the advance payment program. Some may have evidenced a reasonable attempt to protect rate payers from excessive costs; others, perhaps, did not. We do not prejudge the result in any particular case; such determinations are for the Commission in the first instance.

In sum, we remand these cases because the Commission failed to apply the proper legal criteria when it adminstered the "reasonable timing" aspect of the "reasonable and appropriate" standard. The advance payment orders did not require adherence to strict line-of-credit or other conventional banking practices, but rather were instinct with the attitude of flexibility and experimentation that motivated the advance payment program. The Commission correctly determined both that good faith response to competitive pressures was an inadequate justification for advance payments and that the pipelines had a responsibility to protect their rate payers from excessive costs, *e.g.*, to take reasonable steps to ensure that the timing of advances was tied to that of "qualifying expenditures." But the advance payment orders allowed a certain discretion to the pipelines and encouraged them to develop practical financing packages that would facilitate capital formation by producers while adequately protecting consumer interests, thus keeping advances within the confines of the program. Application of the correct legal standard on remand requires consideration of the various factors pertinent to a determination of the reasonableness *vel non* of the pipelines' efforts in this direction.

Account 166 on the same basis as advances to non-affiliated producers. However, there is no limitation in the orders restricting the Commission's ability to consider the affiliate relationship as one factor pertinent to application of the reasonable and appropriate standard in determining which advances included in Account 166 qualify for rate base-treatment.

2. *Latitude on remand.* The Commission has latitude under its statute to use its equitable discretion and to choose alternative procedures or mechanisms to formulate and to effectuate its judgment;[91] the result need not require a painstaking readjustment of rate base in each case.

The Public Service Commission of the State of New York, an active and helpful participant in all phases of the development, administration, and review of the advance payment program, calls our attention to the interrelationship between the Commission's ruling on the advance payment question and its determination on rate-of-return. In the *Tennessee* proceeding,[92] the Commission readjusted upwards the return on rate base allowed by the administrative law judge, on the basis of a revised assessment of the risks faced by the industry in these times of acute supply shortages. In the Commission's view, the "pendulum has definitely swung in a direction substantially contrary to the interests of the investor. A time of adjustment is clearly called for." [93] One of the risks incurred by the pipelines has been the "regulatory risk" that an experimental program such as advance payments might miscarry, and that administrative readjustment would not prevent substantial adverse impact. Commissioner Smith, whose vote in *Tennessee* was necessary to form the majority, expressly premised his concurrence on the link between treatment of advance payments and rate of return.[94] On remand the Commission will have

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[91] FCC v. Pottsville Broadcasting Co., 309 U.S. 134 (1940); Vermont Yankee Nuclear Power Corp. v. NRDC, 435 U.S. 519 (1978).

[92] No. 77-1496 *et al.*

[93] Opinion No. 769, *supra* note 44, at 22; JA at No. 77-1496 *et al.* at 341.

[94] *Id.*, Commissioner Smith, concurring, at 4; JA in No. 77-1496 *et al.* at 357 ("The overall result [on rate of return] is

discretion to consider this interrelationship in reaching a just result. In the other two cases before us, the rate-of-return issue was settled prior to determination of the advance payment question. If the Commission prefers to use rate of return as the vehicle for adjustment, it may consider whether it should reopen these settlement agreements.[95] Another mechanism for effecting the final just and equitable result is the ordering of only partial refunds, rather than the readjustment of rate base. The Commission retains a broad discretion in such matters.[96]

One other significant factor that the Commission may consider in exercising its latitude on remand is the impact on the industry of the entire course of Commission action in the development and administration of the advance payment program.[97]

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supportable only because of the treatment given advance payments.").

[95] By purporting to "settle" rate of return yet leaving open the treatment of advance payments, such settlements may have been rooted in an erroneous premise that these issues could be put in separate analytic compartments and resolved independently.

[96] As noted in Niagara Mohawk Corp. v. FPC, 126 U.S. App.D.C. 376, 382, 379 F.2d 153, 159 (1967), "the breadth of agency discretion is, if anything, at zenith when the action . . . relates primarily not to the issue of ascertaining whether conduct violates the statute, or regulations, but rather to the fashioning of policies, remedies and sanctions."

[97] In another context, we approved the Commission's determination to ignore the varied impact on producers of the advance payment program, and to make a "clean start" in its prescription of a national rate. The Second National Natural Gas Rate Cases, 186 U.S.App.D.C. 23, 59-64, 567 F.2d 1016, 1052-57 (1977), *cert. denied*, 435 U.S. 907 (1978). But that situation involved allocation among producers of uneven *gains*, and prescription of rates for the future. The pipelines are in a different posture. The Commission has latitude to consider whether the pipelines were caught between a rock and a hard

It is appropriate to conclude our discussion of Latitude on Remand, before going on to subsidiary issues, to emphasize that while the court has identified a number of factors for consideration by the Commission, it is aware that the appraisal and weighing of these factors is the function of the agency and not of the court. It is not an encroachment on the agency's ultimate discretion either that the court has identified a number of factors for consideration, or that Judge Wilkey has indicated that in his view a particular emphasis should be given to certain factors. The court's role, permitting intervention for error of law or arbitrary action, still leaves the agency

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place and took actions which they reasonably believe were in the best interests of their customers. This appears to be the thinking of the Public Service Commission of the State of New York. PSC Br. in No. 77-1498 at 14.

There is the further consideration that the ambiguity of the advance payment orders on the timing question may have served the producers as a kind of legal lever to overcome pipeline resistance. In the context of an exception to settled principle, which permitted some "advance" payments, the combination of FERC indefiniteness in the first instance and inaction later on may have given momentum to extended front-end advances. If the FERC takes the view that the ability of the pipelines to resist untoward advances was materially weakened by the agency's handling of the issue, it has latitude to take this into account. In this regard it would be appropriate for the Commission to consider the contrast between Order No. 465, with its absence of any explicit reference to the timing issue, and the notice provided to both pipelines and producers in Order No. 499 that advances must be appropriately expended by the producer within a "reasonable time."

The impact on the natural gas industry of the advance payment program has been likened to the mark left on a landscape by the wreckage from an airplane disaster. *The Second National Natural Gas Rate Cases, supra*, 186 U.S.App.D.C. at 64, 567 F.2d at 57. The Commission has latitude in the circumstances to fashion an equitable allocation of burdens between the rate payers and the pipeline investors.

with a function broader in scope than the court's.[98]

Although our ruling pertains to the rate-base determinations raised by the petitions before us, the Commission has flexibility to consolidate these with other cases, to engage in rule making, or to adopt other procedures. In the end, the Commission may choose to adopt a simplifying formula in the interests of feasible administration; but such a resolution must reflect a reasoned consideration of all the pertinent factors, demonstrating the flexibility that always has been inherent in the advance payment program.

II. Other Issues in No. 77-1496, *et al.*, *Tennessee Gas Pipeline Co. v. FERC*

We turn to two subsidiary questions raised by the petitions for review.

A. *Canadian Advance Payments*

The first question is whether the Commission properly excluded from Tennessee's rate base advance payments made to a Canadian producer. We approve the Commission's determination.

The Commission affirmed the ALJ's decision to exclude from rate base $37.5 million in advance payments made by Tennessee to an affiliated Canadian producer, for use in exploration and development activities in the Canadian Artic Islands, a remote area in the northern reaches of Canada.[99] We discern that the principal basis of the

[98] The vitality of these principles appears from their early statement, *e.g.*, FCC v. Pottsville Broadcasting Co., 309 U.S. 134 (1940), and their recent reiteration, *e.g.*, FERC v. Pennzoil Producing Co., 99 S.Ct. 765 (1979), discussed in note 81 *supra*.

[99] Opinion No. 769, *supra* note 44, at 33-34, JA in No. 77-1496, *et al.* at 352-53; Opinion No. 769-A, *supra* note 32, at 10-13, JA in No. 77-1496, *et al.* at 401-04. *See* JA in No. 77-1496, *et al.* at 297 (map).

Commission's determination was Tennessee's failure to demonstrate "that receipt by the appropriate American consumers of the Canadian gas . . . will most likely occur." [100]

The advance payment orders were expressly limited to domestic advances.[101] The Commission stated that "[t]he sole basis for even considering Canadian advance payments is our prior statement that pending a Canadian advance payment rulemaking such advances 'shall be treated on a case by case basis.' " [102] The Canadian advances were made in 1973 and Tennessee sought to have them charged to the contemporaneous rate payers, though it concedes that no gas will be forthcoming until the mid-1980's.[103] These advances were not "used and useful" for providing service to then current rate payers, and traditional rate making principles would call for exclusion from rate base.[104] The Commission's analysis seems to contemplate an exception from traditional principles, permitting rate base inclusion on a showing that a particular advance payment served the same purposes, and promised an equivalent benefit to rate payers, as those envisioned for domestic advances complying with the advance payment orders.

The fundamental objective of the advance payment program was to help elicit requisite gas supply by providing capital for expedited development and production during the interim period until an upward revision in

[100] Opinion No. 769-A at 12, JA in No. 77-1496, *et al.* at 403.

[101] *See* note 25 *supra*.

[102] Opinion No. 769-A at 11, JA in No. 77-1496, *et al.* at 402, *quoting* Notice of Rulemaking, *supra* note 25, 38 Fed. Reg. at 1056.

[103] *Id.* at 13, JA in No. 77-1496 *et al.* at 404; Tennessee Br. in No. 77-1496, *et al.* at 66.

[104] *See* text accompanying notes 51-55 *supra*.

producer rates would accomplish this objective.[105] The ends of the program could not be furthered unless the investments that were precipitated by advance payments inured to the benefit of jurisdictional rate payers. For this reason the program expressly assured that rate payers would not be charged for advances that did not produce gas, or that produced gas which did not flow to the advancing pipeline.[106] Similarly, as to Canadian advances, the Commission here required that the gas resulting from such advances must be shown "most likely" to flow to the advancing pipeline's domestic rate payers. This general approach was well within the Commission's broad discretion and consistent with that taken in previous adjudications.[107]

More specifically, the Commission concluded that Tennessee had not carried its burden of showing that Arctic Islands gas would "most likely" flow to rate payers in the United States. Several uncertainties remained, *e.g.*: (1) whether reserves in the Arctic Islands region were sufficient to justify construction of a pipeline; (2) whether, at the time this gas would become available for market, Canada's total reserve situation would justify granting of the necessary export authorizations by the National Energy Board of Canada (NEB); and, (3) whether, assuming the existence of adequate reserves, the NEB would grant the required authorizations, rather than authorizing additional exports from other gas-producing regions, or otherwise modifying Canadian energy policy. As we recently have had occasion to note, in the present era of uncertainty for natural gas supply any attempt to pre-

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[105] *See* text accompanying notes 56-66 *supra*.

[106] *See* note 34 *supra*.

[107] *E.g.*, Opinions No. 672 & 672A, Texas Eastern Transmission Corp., Docket No. RP70-29, *et al.*, 50 FPC 1419 (1973), 51 FPC 258 (1974), *aff'd*, 171 U.S.App.D.C. 25, 517 F.2d 1299 (1975).

dict NEB export policy is highly speculative.[108] The very existence in this case of a genuine dispute over the interpretation of a series of inconsistent and conflicting NEB reports is sufficient to support the Commission's judgment that the issue is not free from substantial doubt. We will not disturb the Commission's informed judgment when it acts as here, within an area of its special expertise and discretion.

B. *Rate of Return*

The second subsidiary issue is whether the Commission erred in allowing Tennessee a 13.75% return on equity.

In proceedings before the administrative law judge, Tennessee argued for a 13.35% rate of return on equity; Staff proposed an 11.6% return. The ALJ concluded that a return of 12.5% on equity was "reasonably in line with earnings of enterprises with comparable degrees of risk, and which have similar ratios of common equity capital." [109] The Commission set aside this determination and adopted a return of 13.75%. In the Commission's view, the "pendulum [had] definitely swung in a direction substantially contrary to the interests of the investor. A time of adjustment [was] clearly called for." [110]

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[108] Midwestern Gas Transmission Corp. v. FERC, —— U.S. App.D.C. ——, 589 F.2d 603 (1978) (ruling, *inter alia*, that certain of petitioner's claims were not ripe for review since they depended on the speculative effect on future NEB export policy of FERC action regarding the Alaska Natural Gas Transportation System). *See id.* at 622 n.107.

[109] Initial Decision in No. 77-1496 *et al.* at 23, JA in No. 77-1496, *et al.* at 307. This ruling would have resulted in overall return on rate base of 8.787%. *Id.*

[110] Opinion No. 769-A at 22, JA in No. 77-1496, *et al.* at 341. This ruling resulted in an overall return on rate base on 9.25%. *Id.* at 23, JA in No. 77-1496 *et al.* at 342.

New York Public Service Commission argues that the Commission's ruling on rate of return was inextricably bound to its advance payments determination.[111] PSC also challenges the reasonableness of the allowed return on equity. We have suggested that on remand for reconsideration of the advance payments determination, the Commission should again evaluate the rate of return question, which it would have full authority to do even if the allowed return were valid in all respects, *FCC v. Pottsville Broadcasting Co.*, 309 U.S. 134 (1940). We think it appropriate to refrain from entering a ruling at this time on this issue, pending further consideration on remand.

III. Other Issues in No. 77-1712, *Transcontinental Gas Pipe Line Corp. v. FERC*

Two subsidiary issues are raised by Transco's petition for review: (1) whether the Commission erred in excluding from Transco's rate base expenditures for unsuccessful alternative gas supply projects; and, (2) whether the Commission properly rejected an offer of settlement. We affirm the Commission's rulings.

A. *Expenditures for Alternative Gas Supply Projects*

The Commission affirmed the ALJ's exclusion from rate base of over $22 million expended by Transco in four unsuccessful projects related to the production of synthetic natural gas (SNG).[112] The pipeline argued

[111] *See* text accompanying notes 92-95 *supra*.

[112] Expenditures of $10.1 million related to a study of the technical and economic viability of converting Middle Eastern crude oil into synthetic natural gas of pipeline quality. Over $9.8 million was devoted to a project for conversion of naptha feedstock into SNG. A study of a program to use natural gas reserves located overseas by converting the gas to crude methanol at its source, transporting the methanol by conventional tankers to the United States, and converting the methanol into natural gas cost $1.4 million. Over $920.000 was spent on a project to produce methane from coal. Initial Decision in No. 77-1712, *supra* note 26, at 5-7, JA in No. 77-1712 at 122-24.

that these amounts should be included in rate base to be amortized as expense items for inclusion in cost of service. Thus Transco sought both a return *on*, and the return of its investments. The Commission found that the expenditures were not "used and useful" in providing service and should not be charged to the rate payers.[113] Since the projects did not produce any jurisdictional gas, this ruling clearly was a proper exercise of discretion.[114] We find without merit the claim that the Commission had established a policy, relied on by Transco, creating an exception from the traditional "used and useful" principle with respect to expenditures for SNG development.[115] The Commission had established such an exception for research and development costs, but the Transco projects failed to qualify for special R & D treatment.[116]

[113] Opinion No. 801-A, *supra* note 46, at 2-3, JA in No. 77-1712 at 202-03.

[114] *See* text accompanying notes 51-55 *supra*.

[115] The Commission had previously demonstrated its reliance on this principle in Tennessee Gas Pipeline Co., Opinion No. 624, 48 FPC 149 (1972), *aff'd*, 159 U.S.App.D.C. 318, 487 F.2d 1189 (1973) (grant of a certificate to construct liquified natural gas facilities conditioned to prevent rate-base treatment of costs if the project proved unsuccessful). In addition, the Commission's uniform System of Accounts for Natural Gas Companies, 18 CFR 201 (1978), provided clear notice that pipeline investors must absorb costs of abandoned projects involving "preliminary survey plans, investigations, etc. made for the purpose of determining the feasibility of utility projects under contemplation . . . to provide a future supply of natural gas." *See* PSC Br. in No. 77-1712 at 11.

[116] *See* 18 CFR 201(103) (1978) (requiring, *inter alia*, use of experimental technology and prior Commission approval—

These expenditures were prudent investments, argues Transco; however, for rate base inclusion expenditures must satisfy not only the necessary condition of prudent investment but also must be "used and useful" in providing service. The Commission did not abuse its discretion when it applied a policy "that SNG expenditures which do not qualify as R & D can be recovered, if at all, only through the price paid for actual SNG production sold in interstate commerce." [117]

B. *Rejection of Transco's Settlement Offer*

On the basis of the above reasoning, we affirm the Commission's concise rejection of a settlement offer that proposed to exclude these project costs from rate base, yet to amortize most of them over a five-year period for inclusion in cost of service, thus allowing Transco to recover its unsuccessful investments.[118]

Affirmed In Part; Remanded In Part For Further Consideration.

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both absent from Transco's projects); Opinion No. 801-A at 3, JA in No. 77-1712 at 203.

[117] Opinion No. 801-A at 4, JA in No. 77-1712 at 204.

[118] *See* Opinion No. 801 at 8, JA in No. 77-1712 at 172.

WILKEY, *Circuit Judge* concurring: I concur in Judge Leventhal's carefully reasoned and skillfully crafted opinion for the court. I add this note as a concurrence-for-emphasis.[1]

In Judge Leventhal's opinion for the court the Commission has properly been allowed wide discretion in fashioning a new and more flexible rule on remand. The point I wish chiefly to emphasize is that the Commission on remand must give careful consideration to arguments raised by petitioning pipelines concerning market pressures, the ambiguity of the Commission's orders on timing of payments, and the contribution of advance payments to capital development by producers and to enhancement of gas supply. Thus I believe the court's opinion must be read as not allowing the Commission discretion to institute a new rule that is little more forthcoming in its allowances for advance payments than the now-void thirty-day rule.

As we have noted, the advance payment program constituted a significant and recognized departure from traditional regulatory principles.[2] This departure was deemed necessary to serve the important public purpose of "facilitat[ing] capital formation by [natural gas]

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[1] *See Citizens to Save Spencer County v. United States Environmental Protection Agency*, No. 78-1002 *et al.* (D.C. Cir. 27 March 1979) (Leventhal, J., concurring).

[2] *See, e.g.*, slip op. at 9 (advance payment program was a recognized "departure from the usual rule of public utility regulation . . . that current rates should reflect the cost of supplying service to current rate payers . . ."); *id.* at 31 (describing advance payment program as a clear "departure" from, and "modification" of the "used and useful" principle); *id.* at 43 ("Any permission to transfer advances prior to gas delivery . . . entailed some variance from the . . . [regulatory] situation [prior to the commencement of the advance payments program], in terms of benefit to producer and of cost to pipeline and customer.").

producers to finance development and production of new . . . supplies" in order to "alleviat[e] the impending natural gas shortage." [3] The program aimed to stimulate the process of capital formation by allowing the transfer from pipelines to producers of interest-free sums reasonably targeted for purchase or expenditures for production of identified gas supplies.[4] Natural gas producers were thus relieved of financing costs ordinarily associated with the accumulation of capital for exploration and development of new supplies.

With such significant advantages to be gained from advance payments, it is certainly correct, as Judge Leventhal has pointed out, that producers could be "expected" to bargain with the pipelines for advance payments to be made.[5] Likewise, producers could be expected to press the pipelines for advances to be made on the most favorable terms possible—*i.e.*, as long as possible in advance of their eventual "qualifying" expenditure.[6] This pressure for what we have termed "extended front-end" advances [7] was increased because the availability to producers of interest-free advance payments became one of the few

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[3] *See id.* at 7. *See also id.* at 14 ("theory" of the program was that "increased availability of capital would encourage investment, which in turn would yield additional gas supply").

[4] *See id.* at 42 ("A producer receiving an extended front-end advance, to use without restriction for a significant period prior to expenditure, is in effect given a sum of money.").

[5] *See id.* at 8.

[6] The court's opinion has employed the term "qualifying expenditure" to identify "those producer expenses permissible under the [advance payments] program." *See id.* at 8.

[7] The court has devised the novel and useful term "extended front-end advance" to describe those advance payments barred from current rate base treatment by Commission orders here under review. *See id.* at 14.

negotiable terms of gas supply contracts in the otherwise closely regulated natural gas market.

As a result of tight gas supplies during the years of the program at issue here,[8] bargaining attempts of the producing companies met with particular success as pipelines scrambled to secure supplies of gas for customers. Since it was in order to relieve this plight of tight supply that the program was initiated, however, this superior bargaining position of the producers and their consequent bargaining success should have come as no surprise to the Commission.

Furthermore, no evidence on the record suggests that contracts providing for advance payments were negotiated covertly. Instead, all available information suggests that the high degree of administrative, judicial, and public scrutiny afforded the advance payment program made the terms of the vast majority of advance payment contracts well known to outside parties, and certainly to the responsible regulators.

It is thus particularly astonishing that, as noted in the court's opinion, "[t]he advance payment orders [issued by the Commission during the program] did not specify the permissible interval between the advance and its appropriate expenditure." [9] Order No. 465 contained what has properly been described as a totally "unelaborated statement" that advance payments would be allowed only where "reasonable and appropriate," with no specific reference to the critical issue of *how long* in advance of designated use such payments could be made.[10] Subsequently, Order No. 499 made a completely unimpressive advance toward specificity by declaring that

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[8] These years were 1973, governed by FERC Order No. 465, and 1974-75, governed by FERC Order No. 499. *See id.* at 11.

[9] *See id.* at 17.

[10] *See id.* at 20.

only those advances made within a "reasonable time" of eventual expenditure would be allowed.[11] Until long after the expiration of the advance payment program, therefore, the Commission through its applicable Orders provided only the most cryptic and ambiguous guidelines concerning the issue central to the present litigation.[12]

It thus was practically inevitable that the "flood" of advance payments propelled by Order No. 465 did not abate during the time between the two advance payment orders, or thereafter.[13] The Commission bears much responsibility for this situation, for the opacity of the Commission's orders on the issue of permissible timing could only have contributed to the disruptive effect of advance payment bargaining on the otherwise tightly metered minuet of producers, pipelines, consumers, and regulators.[14]

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[11] *See id.*

[12] The Commission order barring current rate base treatment to certain "extended front-end advances" made by Tennessee Gas Pipeline Company, for example, was issued on 9 July 1976, *see* FPC Docket No. RP73-113, Opinion No. 769, more than six months subsequent to the expiration of the advance payment program on 31 December 1975.

[13] *See* slip op. at 21 ("Despite the Commission's signal in Order No. 499 that it intended to focus on the critical timing requirement, the flood [of advance payments] did not abate.")

[14] As noted in the court's opinion, producers may have been "emboldened by . . . [the] indefiniteness [of the advance payment orders on timing]" and therefore the "producers pressed their bargaining advantage, inducing pipelines to make advances long before the funds were used for qualifying expenditures." *Id.* at 17. *See also id.* (pipelines' "weakened resistance" to competitive pressures was materially aided by "[t]he belief (or hope) that the Commission would permit rate-base treatment of extended front-end advances . . . .").

Though the court's opinion in other language has not accepted petitioners' argument that the Commission must be

The court's opinion has bent over backward to emphasize that the lack of clear regulatory guidance weakened the resistance of pipelines to the "untoward advances" of producers in eliciting extended front-end payments by pipelines.[15] We have been somewhat less defi-

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"estopped" from denying current rate base to advance payments because the Commission was on notice of the payments and the pipelines relied justifiably on agency silence, *see id.* at 44-47, the court's view on this issue is perhaps best summed up in its exceedingly cautious statement that "agency silence . . . [with regard to the scope of a departure from a well-rooted regulatory principle] must be construed to mean that traditional [regulatory] principles retain their vitality." *Id.* at 31. This modest statement, however, must be placed side by side with the court's repeated observation that the advance payment program constituted an express departure from recognized regulatory principles. *See id.* at 9, 31 & 43. Thus it is certainly consistent with the court's position to argue that the "vitality" of the Commission's regulatory principles has been diminished at least to the extent that the Commission itself has backed away from those principles. It would be insupportable for the Commission to bind an industry to regulatory principles from which the Commission has itself departed; thus I believe it is only with some difficulty that we conclude that "agency silence" on the issue of timing of advance payments did not convey a tacit and irreversible assurance that advance payments would be upheld if made in full view of the Commission and in arguable compliance with the Commission's ambiguous regulations.

[15] We have suggested, for example, that the Commission on remand has "latitude to take . . . into account . . . the view that the ability of the pipelines to resist untoward advances was materially weakened by the agency's handling of the issue . . . ," *id.* at 55 n.98, and "whether the pipelines were caught between a rock and a hard place and took actions which they reasonably believe were in the best interests of their customers," *id.* at 54-55 n.97. The Commission also has been urged to take into consideration more generally the "significant factor" of "the impact on the industry of the entire course of Commission action in the development and administration of the advance payment program." *Id.* at 54.

nite, however, in suggesting the extent of the relief that should be afforded the pipelines on remand. We have noted that the objective of the advance payment program was to facilitate the development of capital by producers in order to enhance gas supply,[16] and that advance payments by definition involve the transfer of capital from pipelines to producers.[17] We have also noted the argument of the pipelines that all advance payments must be sustained for reason of such a capital contribution, and the contrary argument of the Commission that no allowance should be made for many payments that "for the extended period between receipt [by the producers] and expenditure . . . made no . . . contribution of developmental capital [for 'qualifying expenditures'] while providing producers with a non-price incentive of the type the program explicitly sought to avoid 'as much as possible.' " [18]

The opinion of the court, however, adopts a middle position. While rejecting the pipeline's argument for carte blanche authority to make advances,[19] we have also rejected the Commission's overly narrow view of the role of advance payments in enhancing capital formation and gas supply. Any front-end advance payment, according to this court's definition, is one made prior to its use for "qualifying expenditures." [20] Also we have noted that only a sub-class of front-end advance payments may properly be disallowed current rate base treatment. This

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[16] *See, e.g., id.* at 6-7 & 14.

[17] *See id.* at 13 (an advance payment, as an interest-free loan, "substitutes for capital raised in financial markets"); *id.* at 42 ("A producer receiving an extended front-end advance . . . is in effect given a sum of money.")

[18] *See id.* at 35.

[19] *See id.* at 35-36.

[20] *See id.* at 13.

class of payments on remand will necessarily be smaller than that excluded by the Commission according to the thirty-day rule. Thus we have not determined that every advance is insupportable for the simple reason of its payment prior to expenditure; instead, we urge strict scrutiny only of those payments that may have been "extravagant" because they were made *too long* in advance of qualifying expenditures.

We reach this conclusion, I believe, in part because payments made at any interval (whether thirty days or much longer) in advance of qualifying expenditures inevitably enhanced the formation of capital in the hands of producers, and, unless diverted eventually for other non-"qualifying" purposes, may have facilitated the development of new gas supplies by reenforcing the capital foundation of the producing firms and freeing other funds for immediate productive use. It will be the task of the Commission on remand to define with some specificity and with greater latitude than previously those advance payments that were, and those that were not, "reasonable and appropriate" in conforming to the stated objectives of the program in thus aiding capital development for the purpose of enhancing gas supplies.

I have some difficulty, however, with the court's discussion of the undesirable consequences of competition among pipelines for supplies of gas. Though bidding among pipelines for gas by offering advance payments inevitably had the effect of raising prices, it cannot lightly be assumed that an increase in prices did not lead to a corresponding increase in supply. As a general matter, only in a situation of total inelasticity of supply can an increase in prices not be expected to lead to a corresponding increase in supply. No such situation of total inelasticity has been demonstrated here, and as Judge Leventhal notes, "Even in the regulatory context, market

pressures retain some vitality." [21] Thus it is clearly within the purview of our decision for the Commission to give close consideration to the extent to which bidding for gas supplies had the effect of raising prices and thus enhancing natural gas supply, in keeping with the overall goals of the advance payment program. I believe that the burden of proof rests with the Commission to demonstrate that the new rule it derives on remand distinguishes effectively between those advance payments that reasonably could, and those that reasonably could not lead to an increase in supply commensurate with any increase in price.

The Commission on remand will also want to take careful note of the losses incurred by the pipelines as a result of the Commission's rate base ruling. Though Judge Leventhal has noted for the court that the Commission's action to date has been to defer, rather than indefinitely to disqualify certain advance payments for rate base, he has also noted that "substantial sums were involved" and that "deferral has resulted in considerable losses for the pipelines' stockholders" because of interest lost during the period of deferral.[22] Such losses are not to be taken lightly, and clearly a very close question is presented as to whether these losses are substantial enough to bar the admittedly retroactive clarification by the Commission of the ambiguous language of its earlier orders on the issue of timing.[23]

The Commission will also wish to consider the equities in specific cases of a denial of current rate base to pipeline companies that may have exercised reasonable judg-

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[21] *See id.* at 16.

[22] *See id.* at 27.

[23] *See* cases cited in *id.* at 45 n.77 (hardship on the affected parties a factor to consider in evaluating limitations on retroactivity of agency action).

ment in making advance payments in the context of tight gas supplies and ambiguous regulatory guidance. The pipelines have made out a convincing case that their responsibility to obtain adequate supplies for consumers during a period of scarce supply compelled them to "bid competitively for gas reserves by offering extended front-end advances." [24] Though we have not endorsed application of any "competitive business judgment" rule in this case, we have noted that circumstances may be "anticipate[d] . . . where a pipeline's investors might determine in their sound business judgment that they should take the risks associated with obtaining needed gas supplies, at least where there is a colorable legal argument that . . . [the] expenditures are permissible." [25]

I believe that under the circumstances of this case there was at least a "colorable legal argument" that many of the advance payments made would subsequently be approved by the Commission, and that any exercise of sound judgment by pipeline companies in weighing factors of consumer demand, scarce supply, and ambiguous regulation must not be lightly rebuffed by the Commission on the basis of an imputed greater wisdom of hindsight.

All of the considerations discussed above I understand to be subsumed within the court's instruction that the Commission on remand devise a new and more flexible

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[24] *See id.* at 23-24; *id.* at n.44 (quoting dissenting view of Commissioner Holloman that, *inter alia*, "A pipeline . . . faced with . . . [the] competitive climate [in the natural gas market] would be remiss in its attempts to attach new supplies of gas on behalf of itself and its customers if it did not use . . . [the] tool [of offering extended front-end advances] to enter into gas supply contracts.")

[25] *Id.* at 16-17 n.30. We have also noted that at least one administrative law judge ruling on this case found that a pipeline company's "unchallenged good faith and business judgment . . . qualif[ied] advances as reasonable and appropriate." *Id.* at 24 n.45.

rule concerning advance payments. As noted in the court's opinion, "The advance payment orders . . . were instinct with the attitude of flexibility and experimentation" and "allowed a certain discretion to the pipelines and encouraged them to develop practical financing packages . . . ." [26] Though the pipelines have erred in arguing for an overbroad and overgenerous rule of universal allowances,[27] they certainly have not erred in resisting the Commission's correspondingly narrow and excessively rigid thirty-day rule. As has been made amply clear in the court's opinion, there is nothing pernicious about advance payments *per se*; [28] instead, I believe, only those advance payments that overstrain the bounds of reasonableness may be denied current rate base treatment by the Commission. Having failed once, a serious burden rests with the Commission to buttress its new rule with reasoned support.

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[26] *Id.* at 52.

[27] As noted in the court's opinion, pipelines have argued that "the sole test for determining whether the advance payments made . . . were to be included in rate base . . . [should have been] whether they were made in order to obtain commitments for additional gas supplies." *Id.* at 28.

[28] *See, e.g., id.* at 14.

APPENDIX B

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Richard L. Dunham, Chairman; Don S. Smith, John H. Holloman III, and James G. Watt.

TENNESSEE GAS PIPELINE COMPANY
(A Division of Tenneco, Inc.)
Docket No. RP73-113

OPINION No. 769

OPINION AND ORDER AFFIRMING IN PART AND REVERSING IN PART INITIAL DECISION ESTABLISHING JUST AND REASONABLE PIPELINE RATES

(Issued July 9, 1976)

This proceeding arises under Section 4 of the Natural Gas Act and concerns the justness, reasonableness and lawfulness of increased rates and charges proposed by Tennessee Gas Pipeline Company.

PROCEDURAL HISTORY

On June 15, 1973, Tennessee Gas Pipeline Company (Tennessee) filed revised FPC Gas Tariff Sheets incorporating a proposed annual rate increase from jurisdictional sales of $150,194,754. Then on August 1, 1973, the Commission accepted these revised tariff sheets for filing, suspended the proposed rates for the full five month statutory period, to become effective subject to refund on January 1, 1974, and set the matter for hearing. It did, however, state that Tennessee must file revised tariff sheets to eliminate any facilities which had not been certificated by January 1, 1974

(the Commission had noted that Tennessee included in rate base for its June 15, 1973, filing over $18 million of non-certificated facilities). In response to this Commission directive Tennessee filed on November 30, 1973, further revised tariff sheets in which the annual jurisdictional rate increase had been reduced to $141,719,530.

Hearings were held intermittently from March 26, 1974 through October 29, 1974, before Administrative Law Judge Samuel Kanell, who thereafter on February 3, 1975, issued an initial decision resolving all of the issues presented by the parties. Briefs on exception to this initial decision were filed by Tennessee, Staff, Columbia Gas Transmission Corporation and Consolidated Gas Supply Corporation (Columbia and Consolidated), Berkshire Gas Company, *et al.* (Berkshire), the Public Service Commission of New York State (New York), and Trunkline Gas Company (Trunkline). Briefs opposing these exceptions were thereafter filed by Tennessee, Staff, Berkshire, New York, Columbia and Consolidated, Northern Illinois Gas Company (Northern Illinois), East Tennessee Natural Gas Company (East Tennessee), and Northern Indiana Public Service Company and Peoples Gas Light and Coke Company (Northern Indiana).

SUMMARY

We find that the following findings in the initial decision should be affirmed: (1) Tennessee Gas Pipeline Company's (Tennessee) composite depreciation rate should be increased from 3.6% to 4% as Staff recommended, not to 5.75% as Tennessee filed. (2) Tennessee's Canadian and Non-Canadian unexpended intracorporate advance payments should be disallowed, as Staff recommended. (3) Tennessee's rate base should be reduced because Staff's larger DDA reserve should be utilized. (4) Tennessee's rate base should further be reduced to account for the disallowance of minimum bank balances from working capital.

(5) Tennessee's rate base should also be reduced to reflect use of Staff's larger reserve for accumulated deferred Federal income taxes. (6) Tennessee's cost of service should be reduced to reflect the amortized portion of the Bastian Bay deferred revenue fund being credited to Bastian Bay expenses. (7) Tennessee's cost of service should also be reduced to account for the tax allowance deduction of interest on short-term debt. (8) Tennessee's cost of service should moreover not be reduced by the deduction from tax allowance of geological and geophysical expenses, as recommended by Staff. (9) Tennessee's cost of service should, however, be reduced to reflect lower ad valorem taxes, but not to the full extent sought by Staff. (10) Finally, Tennessee's cost of service should be reduced to reflect Staff's franchise tax figure. (11) Tennessee's method of cost classification, allocation, and rate design, with minor exception, should be accepted, and all the specific customer proposed alterations rejected, except for Staff's change to the SO-4 rate.

We also find, however, that the following findings in the initial decision should be reversed: (1) The composite depreciation rate increase to 4% should not permit a corresponding income tax allowance. (2) Front-end advance payments unexpended by January 1, 1974, should not be disallowed from Tennessee's rate base. (3) Tennessee's cost of service should not be reduced as Staff sought to reflect greater hydrostatic testing expenses and greater research and development expenses.

FACTUAL BACKGROUND

The major elements of Tennessee's proposed rate increase are a depreciation rate increase from 3.6% to 5.75%, inclusion of substantial additional advance payments, and an increased overall rate of return of 9.25%. Numerous other cost of service and rate base increases were also proposed by Tennessee.

Staff alone presented evidence and argument against Tennessee's cost of service as it took the position that only $15,696,391 out of the $141,719,530 proposed annual revenue increase should be authorized by the Commission, leaving a $126 million differential between Tennessee and Staff. Tennessee's filing is based upon a test year ended February 28, 1973, adjusted for known and measurable changes through November 30, 1973.

The other parties to the proceeding, mainly wholesale customers or state commissions, took an active role in this proceeding only in regard to the issues of cost classification, allocation and rate design.

DISCUSSION AND RESOLUTION OF ISSUES

I. Depreciation

Tennessee's annual depreciation rate had been 3.6% as a result of the last rate settlement, but it sought an increase to 5.75% for an initial five year period based on declining gas production. Staff, on the other hand, would have increased the rate to 4%. Tennessee's rate would result in $33,326,358 more depreciation expense than Staff's rate would, and both Staff and Tennessee estimated $65,186,870 of additional revenues needed to provide the 5.75% rate, of which $32,095,207 represents the associated effect upon the income tax allowance in the cost of service.

The Administrative Law Judge adopted Staff's 4% rate and its straight-line depreciation method, rejecting Tennessee's use of the accelerated unit of production method. He found that Staff and Tennessee both basically agreed upon an annual average depreciation rate of 4% but that they disagreed as to the method. He viewed Tennessee's unit of production method as being based on the growing gas shortage, the anticipated reduced plant service life, and an avoidance of excessive future depreciation charges per unit of gas delivered. While he noted prior Commission

approval of accelerated depreciation,[1] he distinguished it because Tennessee has adequate depreciation accruals for prior years.

The Administrative Law Judge found Tennessee's method to be arbitrary in that it unwarrantedly assumes no additional future supplies and charges more depreciation expense to present service. This method was also rejected for Tennessee employs it on a system-wide basis, not relating specific gas reserves to useful life of specific plant.

In authorizing a depreciation rate increase to 4%, however, he conditioned it so as not to include a corresponding increase in Federal income tax liability for no Internal Revenue Service approval of this depreciation methodology change had been received.

Staff only excepts to the tax portion of this ruling, arguing that Tennessee should be allowed to realize the increased depreciation allowance after taxes have been paid.

Tennessee's exception to the initial decision is multifarious: It first of all asserts that the unit of production method [2] is appropriate in cases of supply instability, such as natural gas, and points to various record evidence of its declining supplies [3] to stress the declining usefulness of its

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[1] *United Gas Pipe Line Company*, Opinion No. 645, 49 FPC 141 (1973).

[2] The unit of production method (depletion accounting) establishes a rate of depreciation by using the total units of gas to be sold during a given time period. Unlike the straight-line method in which time is the basis and the useful life of plant is the central focus, with the unit of production method the difference between original cost and net salvage value is distributed by the ratio of annual production of gas to the remaining recoverable gas reserves.

[3] The nationwide reserve-life index has declined to 9.7 years by 1973, Tennessee's reserve-life index being 10.8 years for the same period. Also new reserves are being far outstripped by present deliveries. Present Tennessee curtailment is also noted.

system, quite apart from the traditional service life under straight-line depreciation. It moreover asserts that the unit of production method should be used because it fairly and evenly apportions its remaining investment between present and future consumers. In addition Tennessee contends that its method does assume additional future supplies [4] and that the five year review provision protects the consumer if its gas supplies increase more than already estimated. It also contests the finding that Tennessee's unit cost of depreciation would decline from 7.5¢ per Mcf for the first ten years to 4¢ for the last ten years, pointing to the impact of increasing interim retirements, which the Judge did not consider. Tennessee furthermore would depreciate the distinction made in the initial decision between its case and *United, supra* note 1, arguing first of all that the inadequacy of past depreciation charges is not controlling for it should be forward-looking, and secondly that its system is newer than United's and therefore has more undepreciated investment to recoup.

Tennessee attacks Staff's method which includes all estimated future additions as present supplies, an allegedly faulty assumption in light of the failure of SNG and LNG projects: If forcasted supplies do not materialize, Staff's method would result in either inadequate depreciation accrual or substantially increased unit cost of depreciation for future consumers at a time when the cost of gas supply will also be much higher.[5] It also questions Staff's failure to include the plant investment necessary to attach all the supply additions Staff assumes will result, as well as

[4] One of Tennessee's studies (Table 2, Exhibit 1) shows 8 Tcf addition over 20 years from traditional supply areas, and the other (Table 3, Exhibit 1) shows this same 8 Tcf, as well as another 14 Tcf from non-traditional sources.

[5] Such eventualities resulting from a deferral of depreciation recovery to the future under Staff's method are asserted to violate the Commission's statutory obligation to establish "proper and adequate rates of depreciation" under Section 9 of the Natural Gas Act.

Staff's interim retirements figure.[6] Tennessee also reads Staff's study to require a 5.15% depreciation rate, thereby rendering the holding of 4% devoid of record evidence support. It attributes this discrepancy to Staff only using three of the twenty years covered by the study. It also controverts the Judge's conclusion that Tennessee's study also renders a 4% average annual rate, arguing that it is error to extrapolate the 20 year study to 25 years for major retirements were not considered in the study.

Finally Tennessee excepts to the tax impact finding. It alleges that its depreciation rate for taxes has always been higher than for book or ratemaking purposes, and it argues that, since in its prior rate cases this excess tax deduction was used to reduce its cost of service, it would be incorrect to now require use of the same rate for book and tax purposes. Also Tennessee cites prior Commission orders in which the book and tax depreciation rates were not identical.

We find that the initial decision should be affirmed as to the increase in depreciation rate to 4%. Therefore, Tennessee's depreciation expense for cost of service should be reduced from $116,602,993 to Staff's proposed depreciation charge of $83,276,635. Tennessee did not meet its burden of proof to justify its substantial depreciation rate increase: Its evidence (Exh. 1, T-1, T-10, T-19, 65-69) is primarily a recitation of various reserve-life indices and the focus of its rationale echoes Opinion No. 645, which is no longer viable.[7] While the Court in *Memphis* recognized that the Commission can take into account the exhaustion of natural resources in establishing depreciation rates for a natural gas company, it held that the Commission must first of all find that such exhaustion of natural resources has in fact caused the useful life of the company's property to be

[6] Staff's study employed a .2% interim retirement rate instead of Tennessee's .5% interim retirement rate.

[7] *United, supra* note 1, *rev'd sub nom, Memphis Light Gas and Water Division* v. *F.P.C.*, 504 F.2d 225 (D.C. Cir. 1974).

reduced to the extent that depreciation based solely on physical life is inadequate. The Court continued by stating that, although evidence of a declining reserve life index increases the risk of a shortened useful life, it was "not satisfied with a record that contains only a recitation of the decline of the reserve life index."[8] Tennessee's evidentiary presentation would not satisfy the Court and does not satisfy the Commission.

Staff if the only other party to introduce evidence concerning an increase in the depreciation rate. (Exh. 39, 40, 41, 42, 42A, 43, 43A, 44, 45, 46, 47, 48, S-6, S-7, S-8, and S-9). Is proposed increase to 4% as adopted in the initial decision, should be approved. We completely endorse Staff's methodology which is discussed below; however, we note that since the time Staff prepared its evidence the alternate sources of supply relied upon by Staff (SNG, LNG, Canadian natural gas) have not been realized to the extent advanced by Staff. Accordingly, this 4% depreciation rate could well be inadequate, but we are constrained to adopt this 4% rate: Tennessee failed to satisfy its burden of proof, and the record upon which we must rely does not afford us the opportunity to *sua sponte* forge a different depreciation rate.

It should first of all be explained, however, that, unlike Tennessee's system-wide approach, Staff classified its depreciable property and assigned separate depreciation rates to each property class[9] which resulted in a composite rate of 4%.

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[8] *Memphis, supra* note 7, 504 F.2d at 235.

[9]

Property Classification	*Annual Depreciation Rate*
Offshore Gathering	6.00
Products Extraction	2.71
Underground Storage	2.42
Transmission	3.83
General	4.00

(Exh. S-9, p. 7).

Staff then used the unit of production method, *supra* note 2 to establish the 6% depreciation rate for gathering plant since its useful life is related to the useful life of the gas reserves supplying it. Such a limited application of the unit of production method is reasonable since the useful life of gathering plant is necessarily defined by the ascertainable present and future reserves. (Exh. S-9, p. 9).

The depreciation rates for the other classes of plant were developed using the straight-line remaining life method. This was also a reasonable approach since Staff recognized that possible changing gas flow patterns would have an impact upon the useful lives of extraction, storage and transmission plant. (Exh. S-9, p. 10).

The Court in *Memphis* specifically directed Commission consideration of "current Commission policies designed to increase or sustain industry-wide gas supply," as well as "the probable extent and location of reserves which United might utilize at some future date." *Supra* note 7, 504 F.2d at 235. Staff introduced evidence in this regard (Exh. S-9, pp. 11-22): Alaskan reserves, reserves in the lower 48 states, coal gasification, liquified natural gas from Alaska and overseas, and importation of natural gas from Canada. Staff related these factors to both industry-wide activities and also specifically to Tennessee, concluding that "we are fast approaching a change-over from almost complete reliance upon our own natural gas resources to diversified sources international in scope." Staff then applied these changing gas supply patterns to the various portions of Tennessee's plant to ascertain the proper service life, looking specifically for possible resulting material under-utilization of plant (major retirements). Staff assigned a 28 year average remaining service life to storage plant and that portion of transmission plant which could utilize imported LNG, Midwestern SNG and Canadian gas. It then assigned an 18 year average remaining service life to the remainder of Tennessee's transmission plant and its extraction plant,

that which can only rely on Tennessee's historic southwest gas supply.

From the perspective of the 1972 and 1973 adjusted test period Staff made the "reasoned estimate" of the useful life of Tennessee's plant as required in *Memphis,* and Staff is moreover correct in rejecting use of Tennessee's unit of production method other than for gathering plant because the total number of units to be transported cannot be ascertained with any degree of certainty. The future prospects of LNG importation, SNG and importation of Canadian gas appear dimmer than when Staff prepared its evidence, but based upon the record in this docket, the nature of the Commission's depreciation rate inquiry under Section 9 of the Natural Gas Act (the Commission must make a "reasoned estimate" of the useful life of plant, and its conclusion must fall within a "zone of reasonableness") warrants continued cognizance of the potential impact of such eventualities upon Tennessee's gas supply patterns.

We do find, however, that the income tax condition placed in the initial decision should be removed. Even with this increase in the book depreciation rate from 3.6% to 4%, there will be no need to change the tax depreciation rate since it has been 4.55%. The income tax component of cost of service is the proper forum in which to consider the tax impact.

II. Rate of Return

There are two contested issues with respect to the appropriate rate of return to be allowed Tennessee in this proceeding, *viz.,* the proper earnings level for equity funds devoted to natural gas transmission operations, and the fair treatment of discounts arising from the reacquisition of previously issued debt securities. We turn first to rate of return to be allowed on the equity portion of Tennessee's overall rate of return.

Evidence on rate of return was introduced by our Staff and Tennessee, although other parties argued the issues on brief. Evidence on behalf of our Staff was introduced through the Chief, Division of Finance and Statistics, Ms. Georgia LeDakis; and that for Tennessee by a private consultant, Mr. W. R. Field, supplemented as to the need for additional financing by the President of Tenneco, Inc., Mr. R. E. McGee. Ms. LeDakis found the then current cost of equity to Tennessee to be 11.6%, while the evaluation by Mr. Field yields a range between 13.5% and 14%. The Administrative Law Judge determined the appropriate allowance to be 12.5% to which both Tennessee, the Staff as well as other parties except.

Witness LeDakis presented testimony discussing the various analytical approaches toward financing cost evaluation —with particular emphasis on the cost of equity—followed by a description of the general economic condition of the country, the pipeline industry, Tennessee and other companies found to be comparable to Tennessee.

Much in Witness LeDakis' testimony and supporting exhibits is not subject to serious challenge by any party on cross examination, rebuttal testimony or on brief—nor could it be, having been based on sound regulatory principles and economic analysis. We shall therefore utilize Ms. LeDakis' testimony to set forth several principles which must serve as the foundation upon which to construct a sound rate of return judgment in this proceeding.

We begin with the fundamental legal precepts required in a rate of return calculation. Ms. LeDakis correctly states at page 24 of her direct testimony:

> As established by judicial precedent, the prescribed rate of return under the Comparable Earnings Test must be:
>
> (a) sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit standing and to attract capital;

(b) it must be commensurate with returns on investment in other enterprises with corresponding risk; and

(c) it must recognize the necessity of maintaining a balance between the interests of investors and consumers alike.

As indicated above there appears to be little question as to the appropriate capital ratios to be used or the embedded cost of debt and preferred stock. We shall defer for the moment discussion of the discount on reacquired debt issue, and confine ourselves at present to a consideration of the appropriate equity allowance.

The need for new capital. Witness LeDakis in speaking of the capital needs of the industry states at page 4 of her direct testimony:

> The utilities industry is a capital-intensive industry. Therefore, its needs for capital are comparatively high and cannot be satisfied from internally generated funds. As such, this industry must rely heavily on outside sources of capital. In fact, its dependence on external funds increased greatly in recent years due to the vast need for capital to finance unprecedented expansion. (Special Exhibit GL p. 3.)

While Ms. LeDakis noted the reduction in the rapid post World War II pipeline expansion Witness McGee for Tennessee stated:

> [T]he capital requirements of pipelines for obtaining gas from traditional sources is increasing sharply. For example, as is evident from this case, pipelines must now make substantial advance payments to producers for gas from traditional sources, whereas a few years ago advance payments were not required.

> Moreover, traditional sources of supply alone are not expected to be sufficiently productive of new gas reserves to meet the tremendous gas requirements. Accordingly, Tennessee, along with many other natural gas pipeline companies, is actively involved in plans to obtain gas from non-traditional sources. These plans will require huge amounts of new capital. (Direct p. 8, 9)

He then indicated that Tenneco is becoming very active in acquiring offshore leases at large bonus payments, much capital is needed to transport that gas to shore. Tenneco is also actively planning to import LNG, to manufacture synthetic gas from crude oil and coal, and to bring gas from the Arctic. While the total capital requirements cannot be projected with any degree of exactness, they will be enormous and will far exceed Tennessee's present plant investment. (Direct pp. 8-10.)

It is obvious that hundreds of millions of dollars in new financing will be required to further exploit traditional gas supply scources and to develop new sources. These requirements along with the higher interest rates will require a much higher proportion of future financing through new issues of equity capital, because of interest coverage restrictions. (Id. p. 11, 12)

The risk factors to be considered. Witness LeDakis pointed out in her direct testimony that risk takes several forms, i.e. financial risk, interest rate risk and purchasing power risk. Financial risk is that occasioned by the potential for loss in the event of bankruptcy and falls most heavily upon the equity holders whose interests are subordinate to those of holders of senior capital. Interest rate risk is described as that attributed to the loss of capital due to a rise in interest rates or the cost of money. This risk usually does not fall as heavily upon equity holders. Purchasing power risk is stated to be the risk of loss in

capital value caused by inflation and is said to impact less severely upon equity holders. (See Direct p. 12)

The risk of bankruptcy to utilities is and should be relatively slight at this time. There is little risk of loss of vast portions of sales markets, since utilities are providing essential public services not as susceptible to the vicissitudes of the economic cycle as would less essential goods and services. We need not delve deeply into an evaluation of this form of risk but shall touch upon it again in our evaluation of the earnings comparable groups of companies or industries.

Ms. LeDakis alludes to two additional risks in her discussion of the cost of debt, each of which have an important bearing upon the cost of equity. At page 7 of her direct testimony Ms. LeDakis discusses "financial risk" which from its context is clearly not the same as the financial risk alluded to above, and is described as follows:

> Major financial services such as Standard and Poor's and Moody's indicate the degree of risk via their rating system. Determining "financial risk" is not and cannot be any more formularly than determining a fair return on utility investment. Individual ratings are based on a judgment study of a large number of factors. Although it has never been explicitly stated, the factor which receives primary weight is "earning power." In order to avoid confusion we shall hereinafter refer to this as "earning power risk."

The second additional risk area deals with the company's ability to earn the return on equity found to be necessary in the face of the need to raise additional capital during periods of rising interest rates or attrition. At page 15 Ms. LeDakis states:

> A good case could be made that the cost to the company is the cost of prospective rather than existing debt on

> grounds that rates are designed for the future. However, money rates for all kinds of capital do fluctuate and sometimes the change can be substantial even in the short run. Consequently, if the current cost of debt was adopted as the cost to the company, it would be necessary to change the return granted every time such cost went up or down, an impossible task.
>
> Therefore, the only practical approach seems to be to accept the embedded cost of senior capital as the effective cost to the company and to allow for the difference between embedded cost and prospective cost in the determination of a return on equity.

Mr. McGee of Tenneco testifies to this phenomenon in part, "As the older low cost debt is reduced and new higher cost debt is issued in this period of high interest rates, the embedded cost of debt will increase with a corresponding decrease in the equity return." (Direct testimony p. 8.)

The interest rate risk and the purchasing power risk evaluated. We recognize that in abstract economic theory the interest rate risk and purchasing power risk have separate identities and each can be operative independent of the other. However, in recent years both have been fused in the minds of investors, and the present record does not permit their separate evaluation even if that were desirable. The interest rate risk in theory would turn upon the supply of and demand for investment funds, while the purchasing power risk is primarily a product of inflation. It is equally obvious, however, that the rate of inflation will have an impact upon both the supply of and demand for investment funds. We shall therefore consider the two together. The analytical approach offered by the present record looks to the effects of these risks as they show up in investor reactions and then reflect back upon the economic indicia to seek an explanation of the observed investor behavior. We find this method appropriate for the task at hand.

One indication of investor reaction to changing interest rate and purchasing power risks is the commanded interest rates of corporate bonds. From page 6 of Exhibit 38 it is obvious that extensive changes have occurred in the cost of senior capital.

	Moody's Bond Yields		
Year	Industrials	Railroads	Utilities
1940	3.10	4.30	3.25
1945	2.68	3.06	2.89
1950	2.67	3.10	2.82
1955	3.19	3.34	3.22
1960	4.59	4.92	4.69
1965	4.61	4.72	4.60
1970	8.26	8.77	8.68
1971	7.57	8.38	8.13
1972	7.35	7.99	7.74
1973	7.60	8.12	7.83
Jan. 1974	7.97	8.34	8.27

A marked increase in the investor's price for capital is observed in recent years. Bond yields during the 70's have been almost three times that of the 40's and 50's, and just over one and three quarters the level of the 60's.

The equity market has responded in a similar fashion, though the comparisons do not appear to be quite so dramatic.

Standard and Poor's Daily Stock Price Index
Fourth Quarter—(Third Quarter of 1973)

	Industrials		Rails		Utilities		Composite	
	P/E	Yield	P/E	Yield	P/E	Yield	P/E	Yield
1967	18.57	2.86	12.52	5.12	15.02	4.33	18.10	3.03
1968	18.38	2.81	14.21	4.12	15.80	4.29	18.03	2.96
1969	16.45	3.22	10.83	5.89	12.17	5.49	15.93	3.43
1970	18.58	3.21	14.39	6.65	13.21	5.14	17.96	3.41
1971	18.72	2.83	14.58	4.10	12.16	5.44	17.91	3.01
1972	19.31	2.44	11.56	4.29	11.65	5.42	18.39	2.67
1973	14.68	2.76	8.93	5.28	10.24	6.21	14.17	3.02

(From Exhibit 38, page 14.)

Each of the categories presented is necessarily affected by the general state of the market at any particular point in time. It is significant that the investing public has substantially downgraded utilities since the 1967-68 period with respect to both rails and industrials, although rails in the latest year 1973 are by far the worst performers. The general market decline in 1969 was followed by a complete recovery in the earnings/price evaluation in 1970 by both industrials and rails. Quite the contrary occurred with utilities which have not since reached their 1967-68 levels. A sweeping reappraisal of value of utility earnings has become manifest in the more recent years.

For corresponding periods of time the Wholesale and Consumer price indices have shown the following:

	Consumer Price Index (1967 = 100)		Wholesale Price Index (1967 = 100)	
Year		Change		Change
1940	42.0		40.5	
1945	53.9	10.9	53.6	13.1
1950	72.1	18.2	81.8	28.2
1955	80.2	8.1	87.8	6.0
1960	88.7	8.5	94.9	10.1
1965	94.5	5.8	96.6	1.7
1967	100.0	5.5	100.0	3.4
1968	104.2	4.2	102.5	2.5
1969	109.8	5.6	106.5	4.0
1970	116.3	6.5	110.4	3.9
1971 (Dec.)	123.1	6.8	115.4	5.0
1972 (Dec.)	127.3	4.2	122.9	7.5
1973 (Oct.)	136.6	9.3	139.5	16.6

(From Exhibit 38, page 2.)

The very dramatic increase in bond yields between 1965 and 1970 followed on the heels of a marked change in purchas-

ing power, particularly as reflected in the Wholesale Price Index. The more dramatic change in the overall stock market prices, however, accompanied the very sharp rise in the Consumer Price Index of 1972 and more particularly 1973. Each response shows investor concern for inflation, the greater overall impact being in the bond market confirming Ms. LeDakis' general conclusion "[E]quity capital does not involve as much *interest rate risk* as do debt capital and preferred stock capital." It is obvious, however, that inflation does have an impact on the cost of equity capital, particularly very high rates of consumer inflation.

Earning Power Risk. The most objective measure of earning power risk is the rating accorded securities by such agencies as Moody's or Standard and Poor's. As indicated by Ms. LeDakis the major factor in ratings of such agencies is the earning power of the enterprise. A frequency distribution of ratings afforded various investment opportunity groups was included in the testimony of Mr. Fields and shows the following. The second or lower portion of the table accumulates the figures from the first or upper portion.

PERCENT OF DOLLAR AMOUNT OUTSTANDING

Ratings	Moody's 24 Electric Utilities	Moody's 125 Industrial Companies	Moody's 10 Natural Gas Distribution Companies	Moody's 10 Natural Gas Transmission Companies
Aaa	21.5	14.9	—	—
Aa	58.0	27.6	39.5	1.3
A	20.5	42.0	69.6	40.1
Baa	[1]	9.9	0.9	44.8
Ba	—	5.6	—	11.1
B	—	[1]	—	2.7
	100.0	100.0	100.0	100.0

[1] Less than 0.1%.

CUMULATIVE PERCENT

Aaa	21.5	14.9	—	—
Aa	79.5	42.5	39.5	1.3
A	100.0	84.5	99.1	41.4
Baa	100.0	94.4	100.0	86.2
Ba	100.0	100.0	100.0	97.3
B	100.0	100.0	100.0	100.0

(From Exhibit —, p. 31.)

It is obvious that Moody's rates the earning power of both natural gas distribution and transmission companies well below, or far more risky, than electrics. In the aggregate natural gas distribution companies fare well in comparison with all but the top few industrials, natural gas transmission companies are considered to be the most risky of any of these groups by a rather substantial margin. On the whole natural gas transmission companies fall some two categories below the electrics and one category below the industrials and natural gas distribution companies. Additionally Tenneco's common was given a rating of B+, the fourth rating on the scale of five. Both the pipeline industry in general and Tennessee in particular are above average in earning power risk.

STANDARD AND POOR'S COMMON STOCK RATINGS

Common Stock Rating	Moody's 24 Electric Utilities	Moody's 10 Natural Gas Transmission Companies
A+	3	—
A	17	1
A—	1	3
B+	3	4
B	—	1

(From Exhibit T-16 pp. 17-18, as corrected Tr. 358.)

Attrition in the allowed rate of return on equity. As indicated earlier Ms. LeDakis testified that the rate of return allowance for equity capital must take into consideration the fact that new debt cannot be issued at its historical embedded cost. Mr. Field included the following table and testimony:

EMBEDDED DEBT COST—TENNESSEE

	Cost	Period to Period Percent Increase	Percent Increase From 12/31/60
December 31, 1960	4.26%	—	—
December 31, 1962	4.56	7.04%	7.04%
December 31, 1964	4.72	3.51	10.80
December 31, 1966	4.98	5.51	16.90
December 31, 1968	5.27	5.82	23.71
December 31, 1970	5.87	11.39	37.79
December 31, 1972	6.52	11.07	53.05
Pro Forma	6.57	.77	54.23

"Thus, since 1960 Tennessee's embedded debt cost has increased about 54%. Moreover, the increase is most likely going to continue for several years. If the Commission continues to allow only embedded debt cost, it must recognize that the resulting return on equity which it determines to be "fair" will not be earned as embedded costs continue their upward trek." (Direct testimony p. 35.)

Mr. Field also introduced evidence intended to show that natural gas transmission company earnings are highly susceptible to dilution through sudden, unexpected cost increases coupled with regulatory lag. The provision of the Natural Gas Act which enables a company to put new rates into effect after a suspension period of not more than five months and the provision in our regulations permitting companies to include purchase gas adjustment clauses in their tariff render this line of argument less pertinent to

companies subject to this Commission's rate jurisdiction than is the case under state regulation. While the argument in the abstract is founded upon some logic, it simply does not apply here.

Comparable earnings. The first prong of the *Bluefield* test set forth by Ms. LeDakis which we will examine is that "the prescribed rate of return . . . must be . . . commensurate with returns on investment in other enterprises with corresponding risks . . . ." All parties agree that there is no single perfect comparative group-allowance based on judgment which must be made in the evaluation of each group. Witness Field set fourth in his direct testimony the following comparisons:

RATE OF RETURN ON COMMON STOCK EQUITY

	1968–1972	1970–1972	1971	1972
Moody's 24 Electrics	11.37%	11.10%	10.98%	11.30%
Class A & B Electrics	12.13 [1]	11.86 [2]	11.53	N.A.
Moody's 10 Gas Distribution	12.18	12.46	12.60	12.16
Moody's 125 Industrials	11.72 [1]	11.17	11.20	N.A.
Moody's 10 Gas Transmission	13.44	13.07	13.26	13.12
Seven Gas Transmission	15.36	14.93	14.81	14.44

[1] Data for 1972 not available; average based on 1967-1971.
[2] Data for 1972 not available; average based on 1969-1971.
N.A. Not available.

The level of earnings for electrics and industrials were down due to the impact of inflation, while electrics were also adversely affected by increasing embedded debt cost and regulatory lag. (Field direct testimony p. 39.) It is

significant that the earnings levels required of natural gas transmission companies is between one and four percentage points higher than that demanded of electrics, industrials or even gas distribution companies. It is patent that the most nearly comparable group of companies to Tennessee is the natural gas transmission companies. However, any comparison with this group "involves a degree of circularity because such transmission companies are regulated by the same regulatory agency." (Field direct testimony p. 39.) As indicated earlier there has been an apparent, substantial downgrading of utility stocks by investors since the 1967-1968 period. This downgrading could indicate insufficient earnings expectations or that prices in the 1967-1968 period were too high. We shall address this issue under the heading *Capital Attraction.*

Mr. Field testifies that "a very conservative comparable earnings test in this proceeding is a comparison of Tennessee with the electric industry. Because of the more favorable risk position enjoyed by electrics *vis. a vis.* natural gas transmission companies, Mr. Field chose to compare Tennessee's earnings requirements to the earnings experienced by the third and fourth quartiles of the electric industry as follows:

	3rd Quartile Point		4th Quartile Range-Mean	
Year	Class A&B Electrics	Moody's 24 Electrics	Class A&B Electrics	Moody's 24 Electrics
1965	13.5%	13.7%	15.4%	15.9%
1966	13.6	14.7	15.6	16.3
1967	13.4	14.9	15.3	16.2
1968	13.1	14.1	15.2	15.0
1969	13.3	14.5	15.1	15.2
1970	13.4	13.1	15.2	14.8
1971	12.9	12.8	14.9	14.0
1972	N.A.	13.8	N.A.	15.1

N.A.—Not available.

In commenting on this table Mr. Field states "[i]t should be emphasized that the above results are for regulated public utilities not unusually profitable or speculative ventures," nor were the earnings in the upper quartile "the result of an unusually high degree of leverage," for "the average common equity ratios . . . were in the 34%-38% range." (Field direct testimony p. 43.) By way of comparison with industrials Mr. Field first constructed a frequency distribution of rates of return earned on average common stock equity for the years 1969-1971 for Moody's 125 Industrials and the calculated following statistics:

	1969	1970	1971
Arithmetic Mean	11.4%	10.0%	9.5%
Median	11.0%	9.3%	9.3%
3rd Quartile Point	13.7%	13.2%	12.6%
4th Quartile Range-Mean	17.6%	16.6%	16.3%

In commenting on this table Mr. Field observed "the operational risk for transmission companies is not so very much unlike that of industrials, it is meaningful that the industrial companies, with the lower *financial* risk implicit in the high proportion of common stock in their capitalization, have earned so well." (Field direct testimony p. 46.) While we appreciate the significant differences in the financial risk of industrial and transmission company stocks it is not persuasively shown that we should accept the third or fourth quartile analysis as an appropriate point of comparison. We are sure that based upon overall risk, including financial, that average industrial earnings should be considerably lower than that of transmission companies. It is also obvious, though, that highly profitable, and perhaps speculative unregulated ventures are included in the upper quartile range. Accordingly, we shall not consider that quartile as an appropriate bench mark for comparative purposes.

Capital attraction. As previously indicated, in order for a rate of return to be fair and appropriate "it must be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit standing and to attract capital" and "it must recognize the necessity of maintaining a balance between the interests of investors and consumers alike." (LeDakis' direct testimony, p. 24.) In striving to balance between the interests of investors and consumers a very complex machinery must be fine tuned—impossible of accomplishment with any high degree of exactness. Under changing economic conditions we find periods when the short run interest of investor or consumer get out of balance. During the period of rapid pipeline expansion and the effecting of economies of scale and improved efficiency the investor interest fared very well. In more recent years the statistics suggest that investor interests have not fared well at all unless common stock was over priced because of unreasonably high earnings expectations as late as the 1967-1968 period. Unfortunately the present record contains only sparse evidence with which to gauge the capital attraction of utilities and more specifically natural gas transmission companies. A good measure of the ability to attract capital would be the market performance of common stocks in relation to their book value. In Ms. LeDakis' opinion the performance of electric common stocks was worse than the market in general, in many instances selling at substantial discounts from book value. While not being able to give specifics Ms. LeDakis indicated that pipelines were also selling at below book but not to the same degree as the electrics. (Tr. 600-601.) Mr. Field on the other hand found there to be virtually no difference in the performance of electric and gas pipeline common stock prices, each having fallen approximately 25-30 percent from the end of 1973 through the early part of July of 1974.

The pendulum has definitely swung in a direction substantially contrary to the interests of the investor. A time of adjustment is clearly called for.

On the basis of the record before us we find that the 12.5% rate of return on common equity found fair and reasonable by the Administrative Law Judge is at or near the bottom of the zone of reasonableness. The upper end of the zone of reasonableness is in the vicinity of the 14% high offered by Mr. Field. It shall continue to be our policy to employ embedded debt cost and preferred stock cost absent a much more persuasive showing of a need to depart therefrom. In addition, financial requirements, continued inflation, dwindling supplies of natural gas and the need for new sources and types of gaseous fuels require that the rate of return on equity be set near the upper end of the zone of reasonableness. We find the appropriate capital structure, capital cost, and ratios to be:

CAPITAL STRUCTURE AND RATE OF RETURN

	Amount	Percent	Cost or Allowance-%	Weighted Cost-%
Long-term debt	$1,184,328	51.05	6.56	3.35
Preferred stock				
1st Preferred	231,556	9.98	7.00	.70
Conv. 2nd Preferred	43,657	1.88	5.48	.10
Common Equity	860,536	37.09	13.75	5.10
Total	$2,320,077	100.00		9.25

Utilizing Tennessee's theory with respect to discounts on reacquired securities would reduce the allowance on common equity to 13.35%. Since we approve the overall rate of return of 9.25% requested, Tennessee's arguments, though incorrect both in precedent and theory, are moot and need not further be addressed herein.

III. Advance Payments

Tennessee sought inclusion of advance payments in the amount of $234,208,422 in rate base, (although in its filed cost of service it included only $208,520,184 of advance payments in its rate base), while Staff would disallow $160,673,309 of that total.

The Administrative Law Judge reduced the amount of advance payments in rate base, although not to the extent sought by Staff. To begin with, he rejected disallowance of advance payments based solely upon failure to utilize the payment within thirty days. He found such a restriction to be undue and not within the Commission's contemplation. He noted that the average time lag between Tennessee making the advance payment and utilization by the producer is about twenty-one months. He also found no evidence to suggest that advance payments were made in excess of producer costs.

Concerning disallowance of advance payments made to Canadian firms, however, the Administrative Law Judge reduced Tennessee's rate base by $37,500,000 because it had not shown that availability of this Canadian gas is assured, as is required by the Commission.[10] In support thereof he took administrative notice of recent difficulties encountered in securing importation of Canadian gas and in establishing a just and reasonable price.

Finally, the Administrative Law Judge scrutinized the $96,500,000 of advance payments made on an intracorporate basis, that is to other Tenneco divisions.[11] He noted that these intracorporate advances were all made within

[10] *Michigan Wisconsin Pipeline Company*, Opinion No. 685, 51 FPC 391 (1974); and *Texas Eastern Transmission Corporation*, Opinion Nos. 672 and 672-A, 50 FPC 1419 (1973) and 51 FPC 258 (1974), respectively.

[11] $59,000,000 to Tenneco Oil Company and $37,500,000 to Tenneco Oil and Mineral Limited (also a Canadian advance).

35 days so as to gain rate base treatment, and that a substantial portion of the non-Canadian advances ($28,216,000) had not yet been expended by the producers and had not been segregated into a separate account or earmarked for exploration costs. In light of the lack of arms-length bargaining as to such intracorporate advances, he found that the unexpended, non-Canadian intracorporate advance payments ($28,216,000) should be disallowed because of the opportunity for abuse, in spite of the fact that intercorporate advances are not so restricted.

Staff excepts to rejection of its rate base adjustment and continues to argue that the consumer should not have to pay the carrying charges for funds advanced far in advance of their utilization since the consumer does not benefit from such advances. Staff would limit rate base treatment to advance payments actually spent by the recipient producers before 1974, including other advances as they are actually utilized by the producers. Staff does not, however, insist on a thirty day time lag limitation so long as the Commission employs a reasonable standard for scrutinizing the reasonableness of advance payments: It views the initial decision as a waiver of such scrutiny.

Tennessee excepts to both advance payments disallowances made in the initial decision, as well as opposing Staff's continued pursuit of a limitation on the time lag between the advance and its utilization by the producer. To begin with, it contends that it was error to disallow unexpended advances on the ground that they were made to an affiliate.[12] It views stated Commission policy in the relevant advance payment regulation [13] to be equal treatment for

[12] As noted above, $28,216,000 out of the $59,000,000 in advance payments made to Tenneco Oil Company for Southern Louisiana exploration was disallowed because it was unexpended.

[13] Order No. 465, 48 FPC 1550 (1972). The Commission therein modified Order No. 441 to give rate base treatment to advances made to affiliated producers.

affiliated and independent producers, which the initial decision allegedly denies in violation of the administrative law precept that an agency cannot in an individual adjudicatory proceeding decline to apply a general rule or regulation:[14] Such disallowance from rate base of unexpended advance payments to affiliates is seen as unlawful retroactive rulemaking by adjudication and can only be accomplished by a subsequent rulemaking amendment with prospective effect.[15]

Tennessee concludes by contesting the factual finding that the lack of "arms-length" bargaining might lead to abuse: In particular the record is cited to demonstrate both the good faith of and the similarity between its agreement with Tenneco's affiliates and those with independent producers. (Tr. 356, 498-500, 507, and 1113). It furthermore derogates the Administrative Law Judge's emphasis upon the proximity in time when these intracorporate advances were made, arguing that timing such advances made so as to receive rate base treatment is consistent with advance payment regulations, that is to permit pipelines to earn a return on the sums advanced. Finally, Tennessee asserts that, since the Commission determines the reasonableness of an advance payment in the context of the pipeline's particular circumstances,[16] the alleged success of the advances to Tenneco Oil Company[17] further enhances the reasonableness of these advances.

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[14] *Service* v. *Dulles*, 354 U.S. 363 (1957); *U.S. ex. rel. Accardi* v. *Shaughnessy*, 347 U.S. 260 (1954); *Arizona Grocery Company* v. *Atchison, T&S Ry.*, 284 U.S. 370 (1932); and *Public Service Commission of New York* v. *F.P.C.*, 295 F.2d 140 (D.C.Cir. 1961), *cert. denied*, 368 U.S. 948.

[15] *NLRB* v. *Majestic Weaving Company*, 355 F.2d 854 (2d Cir. 1966).

[16] *Columbia Gas Transmission Company*, Opinion No. 722, Docket Nos. RP71-18, *et al.*, issued March 7, 1975.

[17] 495,000,000 Mcf of estimated proven reserves have resulted, 291,000,000 Mcf of which are a matter of record. (Exh. T-12 and 70).

Secondly, Tennessee excepts to the disallowance of the $37,500,000 advance payment to Tenneco Oil and Mineral, Limited (TOM) of Canada. Initially, it alleges that these advances for exploration and development in the Canadian Arctic Islands have stimulated substantial activity which should lead to significant new reserves for Tennessee's customers.[18] In addition, it contends that availability of this gas for export is sufficiently assured: Recent increases in estimated reserves in the Arctic Islands and other Canadian areas are seen as satisfying the export standard of the National Energy Board of Canada (NEB), which is to export quantities in excess of Canadian requirements, which in turn are determined to be 25 times the fourth year level of Canadian demand (recently estimated to be 34.2 Tcf). Tennessee seeks further support from optimistic studies by the Commission and Canada, as well as Staff's brief and witness concerning depreciation (it is reasonable to assume the availability of this Canadian gas for import). Similarly, Tennessee anticipates NEB export approval only if continued exploration results in more reserves above Canada's requirements, an eventuality which requires rate base treatment of these advance payments: Tennessee asserts that it could not otherwise raise the necessary E&D capital for TOM. It discounts any remaining risk of non-delivery on the basis of the small cost per Mcf resulting from rate base treatment of this Canadian advance payment.[19] Finally, Tennessee assails the Admin-

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[18] TOM has the right to one-half of all gas available for export developed from over 70 million acres. Tennessee in turn has a right to one-half of TOM's entitlement. Before the entrance of TOM and several cooperating firms into this area in 1971, very little exploration had occurred, but now it is proceeding rapidly (10 wells before 1971, 13 in 1971, 76 by May 1974, and 209 planned for the next four years). 30 Tcf of reserves are anticipated within the next four years.

[19] .44¢ per Mcf of test period sales, and .19¢ per Mcf if 15 Tcf are delivered.

istrative Law Judge's imposition of a burden to assure "beyond any doubt" the availability of this Arctic gas for export, arguing that the Commission has not established such a stringent test and contesting his interpretation of Opinion Nos. 672 and 685, *supra* note 10. Specifically, it reads these opinions as not requiring assurance of advance NEB export authorization.

Thirdly, Tennessee opposes Staff's exception to that portion of the initial decision rejecting Staff's adjustment which would reduce rate base by those advance payments not utilized by the producers within 30 days, such advances known as front-end or lump-sum advances. It first of all finds no intent in Order No. 465 to proscribe front-end advances, asserting that Attachment D thereto demonstrates the existence of substantial front-end advances when the Commission issued Order No. 465, a fact of which the Commission must have been aware. It attempts to reinforce this point by contrasting the express Commission disallowance of certain advances (for lease acquisition and working interest) in Order No. 465 against its silence concerning front-end payments. Additionally, it finds case support for rejection of Staff's position.[20]

Tennessee then attempts to vitiate any support for Staff's position arising from Commission edicts issued subsequently to the advance payments at issue herein.[21]

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[20] *Transcontinental Gas Pipe Line Corporation*, initial decision, 47 FPC 293, 302 (1972); *Trunkline Gas Company*, Docket Nos. RP72-23, *et al.*, initial decision issued November 13, 1974; *Columbia Gas Transmission Corporation*, Docket Nos. RP71-18, *et al.*, initial decision issued January 14, 1974, *aff'd*, Opinion 722, issued March 7, 1975; and *Michigan Wisconsin Pipe Line Company*, Docket Nos. RP73-102, initial decision issued March 31, 1975.

[21] Order No. 499, Docket No. RM74-4, issued December 28, 1973, 50 FPC 2111; and *Natural Gas Pipe Line Company*, Docket No. RP73-110, issued September 4, 1974 (the Commission expressed its intent that advance payments resemble a line of credit, being drawn down as cost and progress dictate).

To begin with, it notes that Order No. 499 expressly is limited to prospective application only, which means that it does not govern this case in which all advance payments were made before December 28, 1973, the date of issuance. Secondly, any present application of the *Natural* order, *supra* note 21, is seen by Tennessee as retroactive in violation of fundamental fairness, noting that the initial decision herein (slip op. at 28, n.1) came to this same conclusion. It states that at the time these advances were made there had been no order issued evincing Commission policy against front-end advances.

Finally, Tennessee attacks the evidentiary basis of Staff's position that front-end advances are unreasonable. The record (Exh. 70) allegedly shows that these advances greatly augmented Tennessee's proved and potential reserves (2800 Bcf), as well as showing (Tr. 498-500) no bad faith on Tennessee's part during bargaining. Assuming the value of these advances to Tennessee's supply situation, it then asserts that pipeline competition in 1973 to secure gas reserves through advance payments was such as to require these front-end advances (Exh. T-12, p. 11 and T-13, p. 3), and furthermore argues that the Commission has recognized these competitive realities in assessing the reasonableness of advance payments.[22] Tennessee concludes by arguing that in any event front-end advances are more effective than installment advances in securing new reserves because they lead to the commitment of all gas in the tract, instead of merely well-by-well commitment following each installment. (Tr. 320). Front-end advances also allegedly stimulate a faster rate of E&D because these lump sums give the producer greater flexibility (Exh. T-12, pp. 13-14 and Tr. 279), and they give pipelines the leverage to tie onshore to offshore tracts. Finally, Tennessee con-

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[22] *Columbia Gas Transmission, supra* note 17, *slip op.* at 8-9; and *Transcontinental Gas Pipe Line Corporation*, Docket No. RP71-31, issued July 30, 1971.

tends that front-end advances are more economical than installment advances: They engender rate stability for the pipeline can ascertain its total financial commitment from the outset, instead of entering an open-ended financial commitment which is subject to cost escalation and inflation, as is the case with installment advances (Exh. T-12, p. 13).

We find that the initial decision should be affirmed in part and reversed in part. Specifically, the Administrative Law Judge's acceptance of Staff's proposed disallowance of Tennessee's Canadian advance payments, and his deletion from rate base of Tennessee's non-Canadian unexpended intracorporate advance payments should be affirmed. His rejection of Staff's elimination of front-end advances should be reversed for the following reasons.

The issue relates to the propriety of including so-called "front-end" advance payments in rate base and passing along to customers charges for debt, preferred stock, common stock and income taxes related thereto. FPC staff presents the view that advance payments under Order No. 465 would be allowed in rate base "where found reasonable and appropriate" (48 FPC 1555), and though there is no specific prohibition against front-end advances, such a prohibition is implicit in the "reasonable and appropriate" standard of that order.

Tennessee urges the decision of the Administrative Law Judge in *Trunkline Gas Company*, Docket Nos. RP72-73, *et al.* (November 13, 1974) as dispositive of the issue, where it was stated:

> ". . . Order No. 465 does not incorporate such a restrictive condition, and there is no showing that Trunkline was given any indication that the advance payments it made would be required to meet a line-of-credit test in order to qualify for rate base treatment.
>
> On the contrary, the evidence is clear that in negotiating advance payment agreements, Trunkline's representatives were motivated by the need to obtain additional gas supplies, and none of the criteria advocated by Staff in this proceeding, or set forth in the Commission *Natural* Order, were factors which Trunkline considered to be guidelines for the conduct of these negotiations, or that Trunkline could reasonably be expected to foresee as guidelines for this purpose.
>
> Basic requirements of due process of law principles and simple justice dictate that new or changed guidelines which are rulemaking in nature, should be applied only prospectively and not retroactively."

There is much to commend the analysis and conclusion of the Judge if the Commission did promulgate new or changed guidelines which are rulemaking in nature. We conclude that neither Order No. 465 nor 499 overturned well established principles of regulatory law on this narrow issue.

In promulgating Order No. 465 and its predecessors, the Commission changed some basic regulatory law for pipelines falling under its jurisdiction. It follows that the full extent of the changes in the body of regulatory law was delineated in those orders. The articulation of the line-of-credit test in Order No. 499 was not a change in the law but was simply a reiteration of existing law. As early as 1936 the U.S. Supreme Court held:

> "The contention is that the amount to be expended for these purposes is purely a question of managerial judgment. But this overlooks the consideration that the charge is for a public service and regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs for these or any other purposes." Acker v. U.S., 298 U.S. 426, 430-431 (1936).

It has, therefore, long been a precept of rate regulation that extravagant or unnecessary costs cannot be passed along to customers through rates. In requiring that advance payments must be reasonable, appropriate and necessary the Commission was but repeating well founded regulatory principles. The Natural Gas Act commands that all rates be just and reasonable. Section 4(a). Furthermore Section 4(e) provides in pertinent part:

> At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the natural gas company . . .

One faced with a decision involving the investment of large sums of money in anticipation of writing the costs thereof to utility customers has known for years that those expenditures must be for a legitimate public service purpose. Any expenditures in excess of common business practice are presumptively extravagant, but subject to rebuttal by appropriate evidence. It has not been suggested by Tennessee that a producer in the conduct of its own business would borrow money and pay interest thereon far in excess of the time it is needed. Nor do we think Tennessee could make such a showing. We find, therefore, that front-end advance payments are presumptively extravagant. A plea that since the Commission has not forewarned that an expenditure might be suspect shifts the burden to prove the justness and reasonableness to the Commission is contrary to the whole body of regulatory law.

Tennessee next argues an estoppel theory by alleging that the Commission was aware that such front-end advances were being made when Order No. 465 was promulgated. Such was not the case. Even had we known of the existence of such advances, the law would not permit us to deal away the rights of consumers to the full protection of the Natural Gas Act.

Nonetheless, if a positive benefit to the consumer can be shown, Tennessee is entitled to rate base treatment of these advances. Mr. Shivers testifies to the benefits to Tennessee's customers as follows:

> "First, Tennessee was able to obtain the commitment of the potential gas involved with a lump-sum advance payment under which, in many cases the total amount of the advance is substantially less than it could be under the installment type arrangement.
>
> Second, lump-sum advances permit the determination of the financial consequences of the advances with certainty at the outset.
>
> Third, I believe that lump-sum advances promote more rapid exploration and development than installment or well-by-well agreements, clearly benefitting Tennessee's customers." (T-13, p. 13)

It is obvious from this record that Mr. Shivers' testimony justifies Advance Payments but not front-end rate base treatment. He cites not one example in support of any customer benefits by reason of front-end rate base treatment. His testimony is spotted with only conclusory statements. While we appreciate expert testimony in cases brought before us, experience and position cannot be substituted for reasoned analyses and supported conclusions.

In conclusion, Tennessee has not made the record in this case necessary to show the reasonableness of including these advance payments in rate base, prior to their actual use by the producer.

The Canadian advance payment issue is more complex, and there are factors supporting both the initial decision and Tennessee. We note first of all that Canadian advance payments have not been specifically authorized under any advance payment order: The sole basis for rate base treatment of Canadian advances is a Commission statement

that pending Canadian advance payment rulemaking such advances "shall be treated on a case by case basis." [23] Therefore, Tennessee can rely on no Commission rule of general application in this regard. In support of the initial decision is the fact that the Commission has consistently disallowed Canadian advance payments in litigated rate cases, *supra* note 10, because of the lack of assurance from the NEB that export authorization will follow. Moreover, by taking administrative notice of the deteriorating Canadian-American natural gas trade,[24] as was done in the initial decision, actual receipt of any of this Canadian Arctic Island gas by Tennessee is doubtful. On the other hand, the aforementioned Commission precedent, *supra* note 10, supporting disallowance of Canadian advance payments has received a judicial setback.[25] In addition Tennessee's evidence (Exh. T-14) suggests that 30 Tcf of reserves will be established by 1978, that Tennessee has a contractual right to a substantial portion of these estimated reserves, *supra* note 18, and that this 30 Tcf could possibly lead to NEB export authorization.

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[23] *Advances to Suppliers for Gas Outside Continental United States,* Docket No. R-466, Notice of Rulemaking, 38 Fed. Reg. 1055 (January 1973).

[24] *Canadian National Gas Supply and Requirements,* National Energy Board of Canada, April 1975; and News Release of Donald Macdonald, Canadian Minister of Mines, July 15, 1975.

[25] Although Opinion Nos. 672 and 672-A have been affirmed on appeal, *Texas Eastern Transmission Corporation* v. *F.P.C.,* 517 F.2d 1299 (D.C. Cir. 1975), Opinion No. 685 was remanded *Michigan Wisconsin Pipe Line Company* v. *F.P.C.,* 520 F.2d 84 (D.C. Cir. 1975) because Commission reliance upon the Opinion No. 672 precedent did not include consideration of the substantial factual differences between the two cases. In particular the Court disapproved of the Commission's failure to address the pipeline's evidence that NEB export policy did not take into account the frontier gas development and that Canadian markets could not absorb the new discoveries from this frontier area.

After balancing all of the aforementioned considerations we find that the $37,500,000 advanced by Tennessee to TOM, should be deleted from rate base, as was done in the initial decision. Upon review of the NEB's most recent statement of position, *supra* note 24, export authorization for this Canadian Arctic Island gas is so unlikely as to render these advances unreasonable and inappropriate: The NEB report indicates that total Canadian demand or requirements will increase greatly in the future, which means that Tennessee's 34.2 Tcf threshold is grossly understated, and Canadian deliverability will not keep pace. Therefore, even assuming that the 30 Tcf of reserves are established and the NEB for the first time finds such frontier reserves to be marketable, there will still be a supply deficiency precluding increased exports.

IV. Other Rate Base Components

A. Reserves for depreciation, depletion and amortization

In determining the proper rate base Tennessee deducted from its $2,108,226,218 investment in plant depreciation, depletion and amortization (DDA) of $817,975,608, this sum resulting from an average of the monthly DDA balances in the base period. Staff, on the other hand, would deduct a greater amount of DDA, $855,322,043, this larger figure resulting from the total DDA account balance nine months after the base period (November 30, 1973, the base period ending on February 28, 1973). This adjustment would reduce Tennessee's rate base by $37,346,435.

The Administrative Law Judge accepted Staff's DDA upward adjustment, reasoning that, since Tennessee employed year-end data for calculating investment in plant, it would be inconsistent to allow Tennessee to then use the average of monthly balances for determining the DDA de-

duction. He found prior Commission approval of this year-end method.[26]

Tennessee excepts to this rate base reduction, justifying its use of the average monthly balance method as being dictated by the then-effective regulations.[27] It then characterizes reliance upon Order No. 488 as unlawful retroactive application since that order was issued after it filing, on July 17, 1973, noting specifically that the Commission expressly limited its scope to filings made after its issuance and that the Commission has recognized the inequity of retroactive effect of rulemakings in other orders.[28]

In the alternative Tennessee argues that in any event Order No. 488 only dictates filing form, leaving the Commission free as to a substantive holding on the issue. In this regard it supports the average method as more closely matching other rate base items (materials and supplies, prepayments, and gas from storage) with DDA.

Staff opposes Tennessee's exception and fully supports the initial decision in this regard.

We find that the $37,346,435 rate base reduction in the initial decision resulting from utilization of Staff's greater DDA reserve should be affirmed and adopted. Apart from

[26] *El Paso Natural Gas Company*, Opinion No. 635, 48 FPC 1022 (1972) (although he noted that the Commission therein set no guideline, he found no evidence supporting this inconsistency in methodology); and Order No. 488, Docket No. R-464, 50 F.P.C. 138 (1973) (he dismissed Tennessee's ex post facto argument that Order No. 488 had been issued after its instant rate filing by reasoning that this order only governs the form of rate filings and in no way circumscribes the Commission's obligation to determine just and reasonable rates).

[27] 18 CFR § 154.63 in effect when Tennessee filed on June 15, 1973, required DDA working papers to show "twelve average monthly book balances."

[28] Order No. 487, 50 FPC 125 (1973); and Order No. 513, Docket No. RM74-18, October 10, 1974.

the retroactive or prospective effect to be given the several versions of § 154.63 of the Commission's Regulations under the Natural Gas Act advanced by Tennessee or considered in the initial decision, it is an established precept of rate-making that revenues, cost of service and rate base must be matched.[29] By calculating its plant-in-service for rate base upon year-end data but at the same time calculating the DDA rate base deduction upon the average of monthly balances, Tennessee diverged from this principle. Staff's adjustment is proper for it rectifies this inconsistency.

B. Minimum bank balances

Tennessee included in its rate base $240,396,579 for net working capital, but Staff sought a $7,518,156 downward adjustment, resulting primarily from its recommended deletion from rate base of that portion of minimum bank balances in excess of ad valorem tax accruals.[30] The Administrative Law Judge adopted this Staff rate base adjustment. He noted that this issue had been previously considered by the Commission,[31] although not conclusively, and he concluded that the 45 day working cash formula (1/8 of operating and maintenance expenses) is sufficient (Tennessee's rate base includes $6,318,796 of working cash under the 45 day formula) and should not be modified by the *ad hoc* inclusion of the minimum bank balance amount since this formula has been found by the Commission to be rea-

[29] *El Paso, supra* note 26, 48 FPC at 1028 and 1029.

[30] Staff's adjustment consists of a $114,149 working capital reduction resulting from the impact of its cost of service adjustments on operating and maintenance expenses, as well as $7,358,422 reduction representing Tennessee's minimum bank balance in excess of the $6,343,614 of ad valorem tax accruals, and a reduction of $45,585 for special deposits. Tennessee's total minimum bank balances were about $13,000,000.

[31] *Alabama-Tennessee Natural Gas Company*, Opinion No. 632, 48 FPC 774, 779 (1972).

sonably sufficient to meet all working capital requirements. He also found no extraordinary circumstances to justify this additional working cash. He furthermore noted that Tennessee's minimum bank balances had been specifically considered in his rate of return determination.

Tennessee excepts to this downward adjustment in working capital which is allegedly reducing its cost of service by $1,119,956 (Exh. 82). Preliminarily, it reasserts the need for these minimum bank balances of $13,700,000 whieh are required by its banking arrangement for a $75,000,000 line of credit. It then attempts to distinguish Opinion No. 632, *supra* note 31, as inapposite (the minimum bank balances therein were less than the accrued taxes while Tennessee's minimum bank balances exceed tax accruals by $7,404,007) while at the same time citing this opinion for the legal principle that minimum bank balances in excess of accrued taxes must be considered in the cost of service, apart from the operation of the 45 day formula. It contests the holding that the 45 day formula is necessarily sufficient for Tennessee's working cash needs, alleging a complete absence of case authority and evidence in support of this holding. Tennessee moreover asserts that since the 45 day formula only relates to the cash outlay for operating expenses it is inadequate to provide for such large working capital requirements as minimum bank balances which it analogizes to the other separate components of working capital (materials and supplies, prepayments and advance payments, 18 CFR § 154.63(f)). Finally, Tennessee refutes the statement in the initial decision that minimum bank balances were considered in the rate of return.

Staff on the other hand, opposes these exceptions and supports the initial decision as to treatment of minimum bank balances.

We find that the $7,518,156 downward adjustment of rate base ordered in the initial decision should be affirmed. To begin with, minimum or compensating bank balances are not

properly includable in rate base via the working capital accounts. Assuming *arguendo* that a portion of short term debt is incurred to finance Tennessee's operations, then the minimum bank balances attributable to that portion are adequately considered in the 45 day working cash allowance (1/8 of operating and maintenance expense less purchase gas cost): The Commission has recognized that since this working cash formula "operates to average shorter and longer payment lag periods," it should not be subject to *ad hoc* adjustments.[32] Moreover, Tennessee has misconstrued *Alabama-Tennessee, supra* note 31, by emphasizing that the offset of minimum bank balances by *ad valorem* tax accruals therein does not exist herein (Tennessee's working capital component for minimum bank balances was the net of $13,702,036 average minimum bank balances (Exh. 6, schedule E-4.6) and $45,585 special deposits (Exh. 6, schedule E-4.3) less $6,343,614 for 7/8 of average *ad valorem* tax accruals (Exh. 6, schedule E-4.4)). When the Commission held that "[minimum bank] balances are properly considered in connection with the rate of return, rather than the working capital allowance included in the rate," *supra* note 31, it meant that minimum bank balances were a cost of capital.

As a matter of Commission regulatory policy for future cases when the proponent of a claim for cash working capital requirements included in rate base for cost-of-service purposes asserts the inadequacy of the Commission's standard formula utilizing forty-five days of cash operating expenses as the appropriate measure thereof, he assumes the burden of showing, by a specific and detailed study, what the actual cash working capital requirements of the company are. This study, known traditionally and customarily as a "net revenue and disbursement lag study," is designed to show individually, and composited, for each

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[32] *Sierra Pacific Power Company,* Opinion No. 730, Docket No. E-8224, issued May 15, 1975 (slip op. at 8).

element of cash revenues and for each category of disbursements for cash operating expenses, including labor, materials and expenses, taxes, insurance and other day-to-day cash expenditures incurred in the course of operations, what lag in collection of revenues is experienced (which gives rise to the need for investor-supplied capital to meet operating requirements,) as offset by the experienced lag in making disbursements to pay bills, reduce accounts and notes payable, meet payrolls, etc., (which has the effect of reducing the need for investor-supplied working funds.) It is axiomatic, of course, that customer-supplied funds do not generate working capital upon which a return allowance should appropriately be provided. The net revenue lag, to the extent that it exists, is then related to cash operating expense requirements, stated as a matter of convenience in terms of the number of days of cash operating expense requirements, and thus becomes an appropriate measure of the cash working capital that is supplied from capital provided by investors, upon which the allowance for return is computed. The foregoing cash requirements are separate and distinct from working capital funds needed to maintain inventories of materials and supplies required for day-to-day operations, inventories of gas needed for operation of underground storage facilities, prepayments of taxes, insurance, rents or gas paid for but not taken under take-or-pay provisions of gas purchase contracts and advance payments to assure future supplies of gas.

There are two alternate possibilities for ratemaking treatment of minimum bank balances. The Administrative Law Judge's statement that he considered minimum bank balances in his treatment of rate of return satisfies neither, as Tennessee properly noted. The first avenue is to account for minimum bank balances by attaching them to the short-term debt component in capitalization, thereby increasing the imbedded cost of debt; however, short-term debt has been permitted into capitalization for the determination of

rate of return only under exceptional circumstances [33] which clearly do not apply to Tennessee.

The alternate avenue is to capitalize the cost of minimum bank balances as part of Allowance for Funds Used During Construction (AFUDC) for future recovery. This of course requires establishment of an accounting convention by which short-term debt is the first source of financing used for construction work in progress. Tennessee did not prepare the cost component of its AFUDC taking minimum bank balances into account; therefore, no rate base consideration can be given to these minimum bank balances. In addition Tennessee's evidence (Exh. 6, schedules E-4.4 and 4.6, T-2, pp. 5-16, and T-11, p. 8) failed to offset its minimum bank balance average sum by the amount of cash it would normally leave in the bank for operational purposes absent any requirement from its banks. Finally, AFUDC is presently pending rulemaking, and the resulting order will govern this matter in the future.[34]

When the Commission referred consideration of minimum bank balances to the rate of return context in *Alabama-Tennessee,* implicit therein was the caveat that the pipeline still had to justify its inclusion in rate of return. Tennessee did not meet its burden of proof in this proceeding.

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[33] *Pacific Gas Transmission Company,* Opinion No. 579, 43 FPC 837, 841-843 (1970); and *El Paso Natural Gas Company,* Opinion No. 582, 44 FPC 73, 84 (1970). The Commission permitted capitalization of short-term debt only because the pipeline had been financially incapable (too low interest coverage) of issuing long-term debt to replace short-term debt which meant that short-term debt was financing part of rate base on a continuing basis.

[34] *Amendments to Uniform Systems of Accounts to Provide for Determination of Rate for Computing the Allowance for Funds Used During Construction,* Docket No. RM75-27, Notice of Proposed Rulemaking issued May 20, 1975.

C. Accumulated deferred taxes

In calculating its rate base Tennessee had deducted from the book value of its plant accumulated deferred Federal income taxes of $45,018,456 (calculated on the test period average reserve). Staff, however, sought to use the actual book reserve as of November 30, 1973, for accumulated deferred taxes, that being $48,903,456. Tennessee countered that anything more than the maximum deduction permitted by the Internal Revenue Service, $46,181,953, could never be claimed by Tennessee for tax purposes. Staff, on the other hand, asserted that its actual book balance figure is permissible under IRS regulations.

The Administrative Law Judge adopted Staff's rate base deduction of $48,903,456 because it is actual, not an estimate like Tennessee's figure. No exceptions were taken to this holding in the initial decision, and we find that the initial decision should be affirmed and adopted in this regard.

V. Other Cost of Service Items

A. Uncontested matters

Of the thirteen cost of service issues resolved in the initial decision only seven have been subject to exceptions. The six uncontested cost of service findings are enumerated *seriatim*:

(1) The Administrative Law Judge permitted Tennessee to depreciate certain intangible plant (franchises and consents), noting Commission authority for the amortization of intangible assets.[35] While Staff had initially sought disallowance of this depreciation expense item $233,601 of depreciation expense and $226,565 of related income taxes), it accepted this amortization in its initial brief.

(2) The Administrative Law Judge did, however, reduce Tennessee's cost of service by $1,026,091 in accord with

[35] *Arkansas Power and Light Company*, 8 FPC 106 (1949).

Staff's proposed excision from Tennessee's initially filed cost of service of an administrative and general expense components for potential liability for Commission fee assessment pursuant to Order No. 427, 45 FPC 403 (1971). After Staff pointed out that such fee assessments had been judicially rejected, Tennessee did not dispute the downward adjustment.

(3) While Tennessee's depletion deduction with respect to its Bastian Bay Project for tax purposes was calculated by Staff to be $1,012,144 more than book depletion (this difference resulted from a lower gas reserve estimate in this filing), it satisfied Staff by its representation that beginning with its 1973 tax return it would file for tax depletion not in excess of book depletion. The Administrative Law Judge made no adjustment to this depletion allowance because he too relied upon this representation by Tennessee. He ordered, however, that Tennessee provide Staff with its 1973 tax return to insure compliance with this representation.

(4) With respect to a pipeline maintenance expense tax deduction Tennessee omitted this item in determining its claimed cost of service income tax allowance (Exh. 11; Exh. 19, Sheet 1, Col. (e), line 18; Exh. S-1, p. 25). Staff thereafter sought a $154,754 reduction in Tennessee's cost of service by using a three year average (1970-1972) for this line maintenance expense tax deduction. The Administrative Law Judge adopted Staff's adjustment.

(5) The Administrative Law Judge moreover adopted Staff's uncontested $500,842 downward adjustment to the cost of service representing inclusion of a three year average of Tennessee's intangible development costs as a tax deduction.

(6) Finally, the Administrative Law Judge accepted Tennessee's $1,696,118 cost of service item comprising severance tax payments to the State of Louisiana.

We find that these six cost of service findings should be affirmed and adopted for not only are they uncontested but they are also proper.

B. Bastian Bay reserves

Tennessee's cost of service for the 1972 test period included $5,001,376 of operating losses arising from its Bastian Bay Field Project;[36] however, it did not include as an offset to these expenses its $1,000,000 incidental revenue reserve fund (this resulted from the sale of condensates) which Staff would employ to reduce the cost of service by amortizing it over a three-year period. Tennessee opposed this adjustment because this revenue reserve fund arose from a one-time non-recurring revenue in 1966, with no such additional revenues anticipated in the future from Bastian Bay. Staff counters that the reserve fund had been explicitly established by Tennessee for the purpose of offsetting expenses in excess of revenues and that Tennessee has in fact claimed operating losses from Bastian Bay in this cost of service.

While the Administrative Law Judge conceded that the reserve fund is non-recurring, he made the offset since Tennessee was claiming the Bastian Bay expenses in this filing; however, in the exercise of his "prudent judgment" and in light of the fact that this reserve fund was established in 1966 and was terminated in 1972, he amortized it over five years. This resulted in a $200,000 reduction in Tennessee's cost of service (⅕ of $1,000,000 equals $200,000).

Tennessee excepts to this $200,000 revenue offset of Bastian Bay operating expenses because this revenue reserve fund is non-recurring, had been exhausted in 1972, and therefore cannot be considered in establishing rates

[36] Gas producing leases in Louisiana owned by Tennessee.

prospectively.[37] It regards the inclusion of the recurring Bastian Bay expenses in its 1972 test period cost of service as immaterial to this issue: Since the reserve fund is admittedly non-recurring and already exhausted by 1972, its use as an offset is unlawful retroactive ratemaking since the rates in this docket are for a future period commencing January 1, 1974 (the effective date of the rates in this docket).

Staff opposes this exception and supports the $200,000 cost of service reduction in the initial decision.

We find that the $200,000 cost of service reduction announced in the initial decision should be affirmed and adopted. To begin with, as has already been noted, Docket No. RP73-113 has been followed by two subsequent Tennessee rate increase filings (RP75-13 and RP75-113) so as to render this proceeding "locked-in", which means that instead of prospective ratemaking the Commission is setting rates for purposes of refund only.

It is clear from Staff's evidence (Exh. S-1, pp. 32-34, Exh. 30, Tr. 556-564) that Tennessee had maintained $1,000,000 as a deferred revenue fund in Account 153 for the purpose of covering Bastian Bay production expenses when Bastian Bay condensate revenues could not meet these expenses. This situation in fact occurred in 1972, and in December 1972 Tennessee transferred this fund from Account 153 to Account 492 (Incidental gasoline revenues) for accounting purposes, although not for ratemaking purposes. Tennessee then included in its rate filing cost of service over $5,000,000 Bastian Bay production expenses for the test year but failed to apply the revenue

[37] Tennessee asserts that Staff witness testified (Tr. 562) that non-recurring items should not go into cost of service. It also views Commission test year regulations, § 154.63 (e)92), as eliminating "non-recurring items." Finally, it cites Commission precedent: *Panhandle Eastern Pipe Line Company*, 25 FPC 787 (1961); and *El Paso Natural Gas Company*, 48 FPC 1022 (1972).

credit. Its sole argument is that use of this $1,000,000 revenue credit to production expense is non-recurring. While this revenue credit to cost of service will not be made every year, the Administrative Law Judge's normalization of this credit, amortization over a five year period, is the proper and equitable manner in which to account for these condensate sale revenues. Clearly, it would be inequitable for Tennessee to increase its cost of service by the Bastian Bay production expenses and yet simultaneously retain the benefit of condensate revenues from Bastian Bay, albeit revenues placed in a reserve fund.

C. Reductions in Federal Income Tax Allowance

1. *Interest on Short-Term Debt*

In computing the income tax liability portion of its cost of service Tennessee made a credit for its interest expense tax deduction. Staff proposed to increase this interest expense deduction resulting in a $375,155 reduction in the cost of service. Staff's adjustment results from inclusion of interest on short-term debt. Tennessee opposed this adjustment on the grounds that Staff did not include short term debt in its rate of return computation.

The Administrative Law Judge adopted this Staff cost of service adjustment. Preliminarily he disposed of Tennessee's argument in that the rate of return he allowed was substantially higher than Staff's recommendation. Moreover, he found Staff's approach to be reasonable and consistent with Commission precedent,[38] and he concluded that, since Tennessee receives the benefit of tax deductions for this interest on short-term debt, failure to reduce the cost of service would be inequitable to Tennessee's ratepayers.

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[38] ***El Paso Natural Gas Company,*** Opinion No. 600, 46 FPC 454, 460-461 (1971).

Tennessee excepts to this portion of the initial decision, arguing that this reduction in the tax allowance violates the rate-making principle[39] that an expense not included in cost of service cannot be used as a deduction in determining the tax allowance for the cost of service since this interest on short-term debt was included in neither the cost of service nor rate of return. (Tr. 1063, and Exh. T-11). It also attempts to distinguish Opinion No. 600: The Commission therein reduced the income tax allowance by the interest paid on short-term debt since El Paso Natural Gas Company had capitalized this interest as a part of its account for allowance for funds used during construction (AFUDC); Tennessee, on the other hand, did not capitalize interest and commitment fees as AFUDC (Tr. 235-236, 1063, Exh. T-11).

Staff opposes this exception and fully supports the $375,155 cost of service reduction made in the initial decision.

We find that the basic adjustment accepted in the initial decision, which resulted in a cost of service reduction of $375,155, should be adopted, subject to further revision reflecting a further change in the allocation of interest expense required to conform with the findings of this Opinion and Order. Initially, the interest paid on short-term debt for the test year which Staff employed to reduce the income tax allowance consisted of $185,721 arising from the gas storage credit agreement and $244,338 arising from the commitment fee for the revolving credit agreement, a total of $430,059. (Exh. 20, Sheet 1, and S-1, pp. 17-18). The interest represented by commitment fees was revised to $201,085 to reflect a different allocation of interest resulting from an uncontested change in Tennessee's capitalization (Exh. 38-A), and resulted in a new total of short-

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[39] ***Midwestern Gas Transmission Company,*** Opinion No. 444, 32 FPC 993 (1964).

term interest, of $386,806. (Exh. 82 (Rev.), Schedule 2, Sheet 6, lines 17 and 19). Since the 48% statutory Federal corporate tax rate is used, the actual decrease in Tennessee's allowance for Federal income tax is 92.308% of $386,806, or $357,052; to this must be added an allowance for state income taxes of $18,103, for a total of $375,155, as asserted by Staff. The record contains ample evidence that Tennessee did not utilize the line of credit available to it during the test year, except during the last twelve days of the period, when a $30,000,000 draw-down pursuant to the $75,000,000 revolving credit agreement was taken, and therefore it did not measurably incur more short-term interest than was given recognition in formulating the tax allowance reduction attributable to the actual recorded interest on short-term borrowings through its $75,000,000 line of credit, which was available as a tax deduction. (Exh. 20, Sheet 3, column (d); TR 4:235, line 24 through TR 4:236, line 7; TR 9:1062, line 22 to TR 9:1063, line 3). With respect to the $30,000,000 draw-down of the credit line, in September, 1973, it was not adduced for the record what repayment terms or rate of interest attached to this short-term borrowing, and therefore what additional actual short-term interest deduction might appropriately be taken into account; accordingly, the Commission is constrained to limit the cost of service tax allowance adjustment to $375,155.

Tennessee's allegation that it did not capitalize interest paid on short-term debt for AFUDC accounting does not distinguish Commission precedent, *supra* note 38 that the tax allowance be reduced by the short-term interest tax deduction even though short-term debt is not factored into the rate of return calculation. In *El Paso* the Commission adjusted the pipeline's income tax allowance by deducting short-term interest payments because it found that, while this interest would be capitalized as AFUDC in rate base so as to be recouped by the depreciation expense with the undepreciated amount earning a return, this tax savings

is not so amortized, which means that the ratepayer will lose the tax benefit unless the interest expense is presently deducted from the tax allowance. Although the Commission was concerned about interest payments on short-term debt which are capitalized as AFUDC, the quintessence of its concern was "a double return on the tax effect involved."

This doubling effect occurs because the income tax allowance, on the "actual-taxes-paid" theory, is overstated when the deduction for actual interest paid is ignored, thus granting the company more by way of return allowance. One of the purposes served by the return allowance is to permit the company to cover its charges for debt service. The return allowance performs double duty when the tax reduction afforded by the recognition of the interest deduction is overlooked. Interest expense on short-term debt is a "below-the-line" charge not otherwise recognized ordinarily as an operating expense ("above-the-line") or in determination of either the *rate* of return or as some element of a component of the rate base. Its inclusion as a tax deduction for cost of service purposes is of course fortified when it *is* so recognized (either in calculating the rate of return or taken into account in determining an AFUDC rate.) But, even if not so used, the "actual-taxes" concept requires its recognition. In the instant proceeding Tennessee has capitalized interest in the AFUDC account,[40] and we attribute short-term debt to construction work in progress.

Tennessee's witness has testified that its short-term borrowings are used for general corporate purposes. (Tr. 235) Without attempting to trace how specific dollars of capital funds are employed, it is patently clear that the interest on such short-term borrowings is nevertheless

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[40] Administrative notice is taken of Tennessee's 1972 FPC Form 2 which at page 544 shows that Tennessee capitalized $1,942,700 of AFUDC by using an 8% return.

available as an income tax deduction as and when incurred, and therefore the rate-payer must realize the tax deduction now or Tennessee will be inequitably enriched by gaining the tax savings and a resultant return increment.

2. *Hydrostatic Testing and Research and Development*

Tennessee also included a deduction for hydrostatic testing expenses in computing its income tax allowance for cost of service (1970-1972) average, the same average employed for several other tax deduction items. Noting that no hydrostatic testing occurred in 1970 and such testing was inordinately great in the 1973 adjusted test year, Staff recommended a 1971-1973 three year average which would cause a $1,935,673 reduction in Tennessee's tax liability.

The Administrative Law Judge rejected Staff's adjustment because no extraordinary circumstance was advanced to justify deviation for the consistent use of the 1970-1972 three year average for tax allowance purposes.

The Administrative Law Judge moreover rejected Staff's recommended $269,630 downward adjustment in determining Tennessee's cost of service. Staff sought to use Tennessee's 1972 research and development expense as claimed in its filed tax return for the tax deduction. The Administrative Law Judge rejected Staff's adjustment because all other expenses of this type, those subject to fluctuation, are averaged over a three-year period.

Staff excepts to both of these holdings in the initial decision because the 1970-1972 three year average is unrepresentative and unreasonable. It views this holding as inflexible and as erroneously overstating Federal income taxes in Tennessee's cost of service.

Tennessee opposes these two related exceptions, charging that Staff is selectively deviating from the consistently employed 1970-1972 three year average merely when another method provides a lower cost of service, employing

the 1970-1972 average only when it would result in a greater tax deduction. It asserts that consistent adherence to the same three year average for all income tax deduction items has the effect of evening out the fluctuations.

We find that the initial decision should be reversed as to the disallowance of Staff's tax allowance adjustment for hydrostatic testing and as to the disallowance of Staff's tax allowance adjustment for R&D expenses. It should be noted preliminarily that the Administrative Law Judge is in error by requiring that all tax adjustments utilize the same amortization. The process of normalization requires an exercise of judgment with the principal objective of developing representative test year expenses for the cost of service. Accordingly, strict adherence to the 1970-1972 amortization formula advocated in the initial decision is fallacious: The specific facts of each item must be scrutinized to arrive at a representative figure.

Concerning the income tax deduction for hydrostatic testing expenses Tennessee amortized the 1970-1972 sum of $3,628,959 over three years, thereby deducting $1,209,653 for test year purposes, while Staff would amortize the 1971-1973 sum of $9,616,335 over three years, thereby deducting $3,205,445 for test year purposes. Staff would therefore increase Tennessee's income tax deductions used in computing Tennessee's income tax allowance by $1,995,-792, which would result in a reduction in Tennessee's cost of service of $1,935,673. This large disparity resulted because Tennessee included 1970, during which no hydrostatic testing expenses were incurred, while Staff included the adjusted test period in 1973, during which $5,866,106 of hydrostatic testing expenses were incurred. (Statement C-1.2, p. 13) Clearly this expenditure during the test year as adjusted is "known and measurable" and should be accounted for. Capitalizing the hydrostatic testing expenses for 1971-1973 and amortizing this over three years, as Staff proposed, is a more representative approach than

that approved in the initial decision. Therefore, Tennessee's cost of service should be further reduced by $1,935,673 (Exh. 82 (Rev.), Schedule 2, Sheet 3).

Similarly, the initial decision should be reversed as to rejection of the Staff's assertion that the single year's tax deduction for R&D expenditures is representative for test year purposes. The Administrative Law Judge's statement that Tennessee used the 1970, 1971, and 1972, three-year average of this cost to compute the proper tax deduction is inaccurate and not supported in the record (Exh. 25 and S-1, pp. 23-24). Tennessee in rebuttal and on briefs directed its attack on the Staff's proposed $612,441 test year tax deduction only to the issue of whether a rigid, mechanical averaging formula should be applied (Exh. T-11, p.6) and the Administrative Law Judge erroneously, as we have indicated, endorsed the same amortization basis. Tennessee charged to administrative and general expense for cost of service purposes an amount of $342,811 representing the annual amortization, on a five year basis, of $1,714,053 of R&D expense capitalized as deferred R&D expenditures. This was viewed by Staff as appropriate, and in accordance with Commission Order Nos. 408 and 483, issued September 3, 1970, and April 30, 1973, respectively. For purposes of calculating the cost of service income tax allowance, however, Tennessee reversed or eliminated the charge to expense, thus creating an offset to tax deductions given recognition for income tax calculation purposes (which, without more, would have the effect of increasing the claimed income tax allowance,) on the ground that such expense, as recorded, was not allowable as a tax deduction (Exh. T-2, p. 9). Tennessee failed to take into account any test period income tax deduction for R&D expenditures even though its filed income tax return for 1972 reflected the deduction of $612,441 of R&D expenditures. (Exh. 19, Sheet 1, Col. (e), lines 7 and 15). There is no evidence of record that Tennessee sought to, or did, elect to apply deferred tax treatment to R&D expenditures permitted by Commission Order No.

504, issued February 11, 1974 (well before, we note, initial briefs to the Administrative Law Judge were due.) Staff properly formulated an adjustment to give recognition to the actual tax deduction available to Tennessee for R&D expenses, utilizing the best evidence available, Tennessee's filed income tax returns. The only issue to be decided therefore is whether Staff's use of one year's R&D versus some average R&D tax deduction is appropriate. Staff reasoned that the use of the 1972 actual tax deduction is more representative of normal test-year R&D expense deductible for tax purposes than any average. We agree.

3. *Geological and Geophysical Expenses*

For 1972 Tennessee had expensed its $173,750 geological and geophysical (G&G) expenses for tax purposes, but it had capitalized them for book purposes. Upon seeing this book treatment of G&G expenses, Staff assumed that the capitalized G&G account was in rate base; therefore, it proposed to reduce Tennessee's cost of service income tax allowance by deducting these G&G expenses. Tennessee responded in opposition by first of all confessing that it had erred by treating G&G expenses inconsistently for book and tax purposes and secondly stating that it was expensing G&G for book purposes too.

The Administrative Law Judge rejected Staff's proposed adjustment, finding it unreasonable to charge this tax deduction to Tennessee's tax allowance when G&G expenses were in cost of service, not capitalized in rate base.

Staff excepts to this holding in the initial decision by arguing that it merely seeks to pass Tennessee's tax saving on to the ratepayers. It does not find G&G expenses in Tennessee's cost of service, and proposes that Tennessee's accounting change to synchronize the book and tax accounting of G&G expenses only be allowed prospectively. It moreover asserts that Tennessee did not prove that G&G expenses were not in rate base.

In opposing this exception Tennessee states that the G&G expenses were expensed and were not included in rate base.

We affirm the initial decision in rejecting Staff's tax adjustment for geological and geophysical expenses. While the thrust of the evidence and argument points to an issue as to reaccounting for expenses recorded, for the most part, incorrectly as alleged and beyond the test period, it is unnecessary to decide this issue. Tennessee's assertion of error, which the Staff does not dispute, casts sufficient shadow over the representativeness of the single-year tax deduction utilized by Staff (Exh. 11, p. 6 and S-1, p. 24) to warrant its rejection.

D. Ad valorem taxes

In computing the cost of service allowance for Tennessee's *ad valorem* property taxes the Administrative Law Judge first of all reduced Tennessee's claimed amount by $1,106,822, this adjustment representing his rejection of Tennessee's projected tax rate trend method and his correlative acceptance of Staff's employment of the actual 1972 ratio of taxes paid. Tennessee did not dispute Staff's methodology, but it did contest Staff's proposed disallowance of $570,539 of increased *ad valorem* taxes payable to the State of Tennessee in 1973 (Staff argued that this increase was not actually paid until after the 1973 adjusted test year). The Administrative Law Judge rejected this latter Staff position because, assuming no error in Tennessee's tax calculation, this $570,539 tax liability was accrued during the 1973 adjusted test year.

Staff excepts to this acceptance of the State of Tennessee 1973 tax increase. Its major premise is that, while this increased tax obligation was accrued for 1973, Tennessee did not actually pay it until after the test year, to wit: February 1974. In addition Staff alleges that in this proceeding Tennessee has consistently calculated *ad valorem* taxes on an "as paid" basis, not on the "as accrued" basis now sought.

In opposing this exception Tennessee first of all factually disputes Staff's allegation that it has used an "as paid" method: Tennessee asserts that it has primarily used a trending method, which Staff itself adopted. Secondly, it reiterates the rationale in the initial decision that this $570,539 tax increase was effective throughout 1973 and that it was accrued in Tennessee's books for 1973. Furthermore, it reads the initial decision as corresponding with Commission filing requirements, § 154.63, Schedule H(4), as well as with the fact that it utilizes accrual accounting.

We find that this portion of the initial decision should be affirmed and adopted. The Administrative Law Judge correctly accepted $1,106,822 of the $1,677,361 Staff *ad valorem* tax reduction because Tennessee's projected trend method for calculating the tax ratio to property investment is speculative and uncertain. Tennessee does not contest this adjustment which applies low tax rates for the various states to Tennessee's proposed tax base which Staff accepts. The Administrative Law Judge moreover correctly rejected the remainder of Staff's $1,677,361 *ad valorem* tax adjustment, that being the $570,539 proposed reduction in Tennessee's *ad valorem* tax payment to the State of Tennessee. This tax liability was in fact accrued during the adjusted test year (Exh. T-11, p. 1), and its inclusion in the cost of service is consistent with Tennessee's accrual accounting. Staff's allegation on brief that Tennessee calculated *ad valorem* taxes on an "as paid" basis is not supported by its evidence (Exh. 29 and S-1, pp. 27-29).

E. Franchise taxes

Tennessee's cost of service computation also included $457,100 representing its estimate of increased franchise tax liability from Louisiana, Mississippi, Pennsylvania and Texas precipitated by its $555,000,000 addition to capital

resulting from the rulemaking change in the FPC Uniform System of Accounts from "cost" accounting to "equity" accounting for long-term investments in subsidiaries.[41] Staff opposed this cost of service item as it argued that Order No. 469 would not result in increased tax liability unless the subsidiary at issue paid a dividend to its parent.

The Administrative Law Judge accepted Staff's adjustment and therefore reduced Tennessee's cost of service by $457,100. He justified this holding by the lack of evidence that these additional franchise taxes had either been assessed or paid.

In excepting to this holding Tennessee first of all asserts that its evidence proves that the four states involved herein consider Tennessee's book equity in computing franchise taxes, which in turn would negate any Commission intent Staff would attribute to Order No. 469. Secondly, Tennessee asserts that it has "substantial exposure" to this franchise tax increase and that it is proper and consistent with Commission precedent [42] to permit recovery of these taxes with a refund arrangement if these taxes are not in fact assessed.

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[41] Order No. 469, 49 FPC 326 (1973). Prior to this accounting rulemaking order long-term investment in subsidiary companies was accounted for in the FPC Uniform System of Accounts by the "cost method: the utility's recorded investment in a subsidiary is unaffected by the results of the subsidiary's operations, and subsidiary income is only recorded when it pays dividends to the parent utility. With this order the Commission adopted "equity" accounting: the parent utility's investment account is increased or decreased to reflect the parents proportionate share of the subsidiary's current earnings applicable to common stock regardless of whether the earnings are actually paid out as dividends to the utility.

[42] *Tennessee Natural Gas Lines* v. *F.P.C.*, 221 F.2d 531 (D.C. Cir. 1954); *Natural Gas Pipeline Company of America*, 50 FPC 151, 152 (1973); *El Paso Natural Gas Company*, RP71-31, *et al.*, issued July 30, 1971; *Natural Gas Pipeline Company of America*, 28 FPC 731 (1962); and *Socony Mobil Oil Company*, 28 FPC 357 (1962).

Staff opposes this exception and supports this franchise tax adjustment in the initial decision.

We find that the adjustment to Tennessee's franchise tax allowance made in the initial decision should be affirmed and adopted. The Administrative Law Judge correctly found that Tennessee's evidence (Exh. T-11, pp. 1-2 and Schedule H(4), p. 2) does not support a finding that its franchise tax liability in Louisiana, Mississippi, Pennsylvania and Texas increased by $457,100 as a result of the Commission-directed equity accounting for unappropriated undistributed subsidiary earnings. In addition the Commission stated in Order No. 469 that it "had no plans to change its ratemaking policy," which is to exclude undistributed subsidiary earnings from the utility's common stock equity in determining rate of return: this statement of ratemaking policy should be raised by Tennessee to counter any state's attempted franchise tax assessment of these undistributed subsidiary earnings. Of course if any state persists in such an assessment, then actual franchise taxes paid would be included in the cost of service; however, there is no proof of that eventuality in this case.

VI. Cost Classification, Allocation, and Rate Design

A. General

Commission determination of Tennessee's just and reasonable cost of service and return on rate base yields its revenue requirement, which must then be translated into the ultimate rates to be charged Tennessee's customers, a process requiring several separate though related operations. To begin with, Tennessee's system must be *functionalized*, the various operations segregated for example into production, storage and transmission. Secondly, costs must be *allocated* between jurisdictional and non-jurisdictional sales, as well as between the various rate zones, if the zonal method of used. At the same time the costs must be *classi-*

fied, which includes separating a portion of fixed costs to the demand charge and the remainder of fixed costs and all variable costs to the commodity charge: The demand charge relates to the customer's basic entitlement to receive gas, and the commodity charge relates to the volumes of gas actually received. Finally, the rates must be *designed* so as to equitably apportion the costs to the various classes of jurisdictional customers.

Tennessee's rate increase filing in this docket incorporated functionalization, cost classification and allocation, and rate design previously prescribed for the Tennessee system by the Commission.[43] Specifically, Tennessee's cost of service was functionalized by production, storage and transmission.

Transmission costs were then classified according to the *Atlantic Seaboard* methodology [44] by which 50% of fixed costs are assigned to the demand charge and the other 50% of fixed costs, as well as all variable costs, are assigned to the commodity charge. Tennessee's cost allocation is directed to its six rate zones,[45] there being no real jurisdictional/non-jurisdictional customer issue. These transmission costs were then allocated among the zones by use of the Mcf-mile method,[46] transmission demand charges allocated

[43] *Tennessee Gas Transmission Company,* Opinion No. 352, 27 FPC 202 (1962).

[44] *Atlantic Seaboard Corporation,* Opinion No. 225, 11 FPC 43 (1952); and *Southern Natural Gas Company,* Opinion No. 228, 11 FPC 123, aff'd. *sub nom., Kansas* v. *FPC,* 206 F.2d 690 (8th Cir. 1953), *cert. denied,* 346 U.S. 922 (1954).

[45] Southern (zone 1), Central (zone 2), Eastern (zone 3), Northern (zone 4), New York (zone 5), and New England (zone 6).

[46] "[T]he volumes delivered at each point within a particular zone are multiplied by the number of miles from the source of supply to such point to derive a total number of Mcf-miles for

by the three day peak Mcf-miles and transmission commodity charges by the average annual day Mcf-miles.

Production costs were also classified according to the *Atlantic Seaboard* method, and they were allocated to the zones on the basis of the average annual day sales.

Since Tennessee renders storage services for specific customers, as well as utilizing its storage facilities for system-wide operations, storage costs are allocated between these two. To begin with, storage costs are classified by assigning fixed costs to deliverability and space and variable costs to injection and withdrawal. Allocation between the specific storage services and system-wide storage is accomplished by use of the percent of storage units used for the storage service out of the total storage units available. Storage costs not allocated to the specific storage services are allocated among the system-wide operations. Storage demand costs (deliverability and space) are allocated by use of the average of the three-day peaks, and commodity costs (injection and withdrawal) are allocated by use of the average annual day.

Tennessee's rate design within each zone moreover utilized the *Atlantic Seaboard* methodology. Demand charges are determined by dividing the demand costs for each zone by the sum of the test period demand billing determinants. Commodity charges are determined by dividing the commodity costs for each zone by the total test period volumes.

The Administrative Law Judge accepted Tennessee's cost classification and allocation and its rate design, finding that the methodology found in Opinion No. 352 remains just and reasonable with no need for alteration. In arriving at this result he rejected several recommended modifications. For

each zone; rolled-in system-wide transmission costs are allocated to each zone according to the ratio of the individual zone's Mcf-miles to the Mcf-miles of the system as a whole." *Supra* note 43, 27 FPC at 207.

example, although Staff agreed with Tennessee's *Seaboard* 50/50 cost classification, it sought for rate design purposes the *United* 25/75 method [47] by which 75% of fixed costs and all variable costs are assigned to the commodity charge and the remaining 25% of fixed costs are assigned to the demand charge. The Administrative Law Judge rejected use of this 25/75 method because, unlike the unused capacity on United's system, all of Tennessee's transmission capacity is needed during peak delivery periods, as well as because of Staff's inconsistent methodology for cost classification and rate design and the fact that Staff's proposed shifting of fixed costs to the commodity charge would not discourage industrial sales, as Staff had contended.

The Administrative Law Judge moreover rejected Staff's minor adjustment to classify supervision, engineering, and administrative and general expenses (overhead) between fixed and commodity (Tennessee had classified all these costs as fixed), although he did adopt Staff's proposal to allocate the remaining storage costs to other system-wide services with the commodity charge allocated by winter season deliveries instead of by annual average day.

Staff excepts to several portions of the initial decision. Initially, it pursues classification of the overhead expenses between demand and commodity, allegedly in accordance with *Seaboard*. Secondly, it reiterates its support for use of the 25/75% *United* methodology for rate design on the grounds that this method would both help to discourage industrial consumption of gas and also develop a commodity charge equal to the cost of replacement gas, although it acknowledges that the present price differential between gas and alternate fuels decreases the feasibility of the former. While it concedes the resulting shift of costs within each zone from low to high load factor customers (from rate G

[47] *United Gas Pipeline Company*, Opinion No. 671, 50 FPC 1348 (1973), *aff'd sub nom, Consolidated Gas Supply Company, et al.* v. *FPC*, Nos. 74-1343 *et al.* (D.C. Cir. October 9, 1975).

to rate CD), it alleges that the shift will only be $1.6 million. It moreover finds that this shift of more fixed costs to the commodity charge is supported by Commission precedent.[48] Finally, it refers to occasions when the Commission has utilized different methods for cost allocation and rate design.[49]

Tennessee, East Tennessee, Northern Illinois, and Columbia and Consolidated all oppose Staff exceptions to the initial decision. They argue that the *United* 25/75 formula is inappropriate because of the absence of excess pipeline capacity on peak days. In addition they rebutt Staff's justification that the 25/75 formula will help to reduce industrial consumption of gas: such manipulation of rate design is beyond the mandate of the Natural Gas Act;[50] end-use curtailment and Section 7(c) conditioning of certificates are more direct means to accomplish this end; the price disparity between interstate gas and alternate industrial fuels is too great to allow such a rate design to dampen industrial consumption; this rate filing has been locked-in by Tennessee's rate filing in Docket No. RP75-13, a fact which the Commission has purportedly found controlling;[51] volumetric limitations previously imposed upon the

[48] *United, supra* note 47; *Colorado Interstate Gas Company*, 50 FPC 41, 43 (1973); and *Natural Gas Pipeline Company of America*, 50 FPC 151, 153 (1973).

[49] *Southern Natural Gas Company*, Opinion No. 379, 29 FPC 323, 342 (1963); *American Louisiana Pipe Line Company*, Opinion No. 387, 29 FPC 932, 943 (1963); *United Fuel Gas Company*, Opinion No. 430, 31 FPC 1342, 1347 (1964); and *Midwestern Gas Transmission Company*, Opinion No. 477, 34 FPC 973, 981-982 (1965).

[50] *F.P.C.* v. *Hope Natural Gas Company*, 320 U.S. 591, 616-617 (1944).

[51] *Consolidated Gas Supply Corporation*, Opinion No. 703, RP71-77, issued August 28, 1974, (Slip Op. at 15).

Tennessee system[52] will prevent anymore industrial growth; and any "tilt" from *Seaboard* will probably not be carried through to the ultimate industrial sale because the state commissions design rates differently. It is also argued that implementation of Staff's second objective, to design a rate having a commodity charge equal to the cost of replacement gas, would be inequitable for it would shift cost recovery to the downstream zones so as to thwart the zonal cost allocation, an impact the Staff witness allegedly foresaw (Exh. S-3, pp. 15-16). It is asserted in addition that Staff's rate design would discourage development of storage capacity with the resulting adverse impact upon high-priority customers since the high load factor customers to whom more fixed costs will be shifted include pipeline customers injecting large volumes of Tennessee gas into storage: Such extensive storage has allegedly assisted Tennessee in avoiding additional construction of transmission facilities otherwise needed to meet peak requirements, a benefit recognized by the Commission.[53]

New York also excepts to the rate design prescribed in the initial decision. In particular it advocates assignment of 75% of fixed costs to the demand charge and only 25% of fixed costs, along with all variable costs, to the commodity charge, this formula allegedly having formed the basis for the rates established in the last Tennessee rate filing settle- approved by the Commission.[54] In the alternative it argues that, if the Opinion No. 352 methodology is followed by the Commission, it should only apply to the cost increases occurring since the rate established in Opinion No. 619. It moreover attacks the merits of the *United* 25/75 formula.

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[52] *Tennessee Gas Pipeline Corporation*, Opinion No. 712, CP73-115 and CP74-27, issued November 26, 1974.

[53] *United Fuel Gas Company*, Opinion No. 430, 31 FPC 1342, 1349 (1964).

[54] *Tennessee Gas Pipeline Company*, Opinion No. 619, 47 FPC 1327 (1972).

Tennessee, Staff, East Tennessee and Berkshire oppose New York's exceptions, and in particular they assail its reliance upon the Opinion No. 619 rate settlement which was a negotiated dollar settlement expressly disclaiming any precedential effect. Moreover, New York's attack upon the *Seaboard* formula is seen as specious since *Seaboard* had been prescribed for the Tennessee system by 1962 in Opinion No. 352.

At the onset, we note that the rates to be determined in this docket have been superseded by rates placed into effect by Tennessee in Docket No. RP75-13 on March 15, 1975. Therefore, we do not rule on the appropriate methodology of cost classification (except as set forth herein, below), allocation and rate design; instead we defer our determination of the proper prospective treatment of these items to Tennessee's rate increase applications in Docket Nos. RP75-13 and RP75-113. These dockets, as well as Tennessee's recent Form No. 16 indicate that Tennessee is currently experiencing substantial curtailments, whereas in this proceeding the test period deliveries indicated no curtailments, and we feel that this change in circumstance should be considered by us before making a determination as to the proper prospective application of cost classification, allocation and rate design.

We do find, however, that Staff's classification of supervision, engineering and administrative and general expenses to be proper. Staff classified these expenses between demand and commodity on the basis of supervised labor. This is the way these expenses have been historically treated and Tennessee presented no evidence to support a different treatment. We also find that Staff's proposal to allocate the remaining storage costs to other system-wide services and to allocate the commodity portion on the basis of winter season deliveries is appropriate. With respect to the first point, it is obvious that Tennessee's method of allocating storage costs (the cost remaining after

allocating storage costs between storage service and all other services) to all services, including storage services, unduly burden storage service and should be rejected. As to the second point, Staff's allocation of storage commodity cost on the basis of winter season volumes more properly measures the relative use of the storage facility and should be approved.

With these adjustments, we find that the *Seaboard* method of cost classification, allocation and rate design used by Tennessee to be appropriate in determining rates for refund purposes. Our determination that the *Seaboard* method is appropriate for refunds should not be construed as tacit approval of *Seaboard* in any pending rate increase application of Tennessee. While we will decide these cases based on the evidential presentations made therein, we specifically invite attention to our remarks concerning rate structure in our recent order approving settlement in Transwestern.[55]

B. Specific proposed adjustments

1. *Seller's Option Rate*

Tennessee had also retained its Seller's Option (S0-4) rate schedule which had previously been approved by the Commission in Opinion No. 352. Under this rate for off-peak service Tennessee has an obligation to deliver at times of its own choosing a fixed annual volume of gas, and the buyer must pay for any volumes so tendered, whether taken or not. Only Columbia and Consolidated take deliveries under this rate, utilizing it to refill gas shortage during the off-peak summer months. The demand charge portion of this rate had historically been only half as much as that for contract demand (CD) service at

[55] *Transwestern Pipeline Company*, Docket No. RP74-52, Order Approving Settlement Agreement Subject to Conditions and Setting Date for Hearing on Reserved Issue, issued March 2, 1974.

100% load factor: The SO-4 rate employes a 200% load factor to impute demand billing determinants. Staff sought to modify this rate by imputing demand billing determinants with a 100% load factor.

The Administrative Law Judge rejected Staff's adjustment and continued the SO-4 rate with a 200% load factor. He noted the historical use of this load factor, as well as the disproportionately high rate increase for SO-4 customers under Staff's adjustment as compared to Tennessee's other rates, in concluding that such an alteration of the demand charge would be inequitable absent a commensurate increase in Tennessee's other rates.

Staff excepts to this portion of the initial decision and restates its position that the SO rate should be priced identically to the CD rate since the service under these two rates is allegedly equal in value: It argues that the SO-4 customers' storage capacity renders this service as valuable as firm service under the CD rate.

Tennessee, along with Columbia and Consolidated, oppose this exception. They note that SO-4 presently comports with Opinion No. 352 and argue that it is not as valuable as CD service because it both entitles the customer to only an annual, not daily, fixed volume. (Tr. 1017-1020) and also requires as a practical matter substantial investment in storage facilities to permit the type of utilization Staff discusses. Furthermore, they assert (Tr. 988-989) that the SO-4 rate benefits the entire system because Tennessee's completion of SO-4 deliveries during the summer valley period has permitted it to avoid the construction of further peak capacity of 43,000 Mcf per day.

We find that maintenance in the initial decision of the SO-4 rate upon the basis of imputing demand billings determinants by using a 200% load factor should be reversed. Since SO-4 is a straight-line rate instead of a two-part rate, it is necessary to impute demand billing determi-

nants, that is a fixed load factor must be assigned. The 200% load factor accepted in the initial decision had been employed historically as it had been accepted in Opinion No. 352. Staff's rationale for use of a 100% load factor (SO-4 service is equal in value to CD service and should therefore have a more equivalent rate) is supported by the record.

The service is firm on an annual basis. Since it is used extensively for storage injection it enjoys a relatively high service priority. Moreover, as Staff points out, the record reveals that Tennessee constructed capacity to serve the requirements under SO-4 on the basis of average annual day deliveries and that average annual deliveries are equivalent to service at 100% load factor. Under these circumstances, we find that the SO-4 rate should be determined on the basis of 100% load factor.

2. *Berkshire's Mcf-Mile Adjustment*

Berkshire had sought to modify Tennessee's cost allocation and rate design with the effect of shifting $7 million of costs from zone 6 (New England) to the other zones.[56] The Administrative Law Judge rejected all of these proposed adjustments, finding that Berkshire had not justified divergence from the cost allocation and rate design established in Opinion No. 352. He noted that allocation and rate design do not lend themselves to mathematical precision but instead require "prudent judgment" so as to attain equity among customers. In particular he found

[56] Berkshire advanced the following proposals: decrease the New England customers' Mcf-miles by computing a portion of them from storage which is much closer to New England than are the sources of Tennessee's pipeline supplies; reallocation of storage costs by use of "actual cost" (the excess of peak-day sales over average-day sales); shift of some transmission depreciation expense from mileage related components to system-wide components; and classification of 5% of fixed costs to commodity and 35% to demand.

that the Commission in Opinion No. 352 had adequately rejected this same attempt to segregate facilities (the zone-gate method of cost allocation) as it concluded that Tennessee operates a fully integrated transmission system with essentially the same type of service in all zones and that all facilities, including storage, benefit all customers whatever their zone. In addition the Administrative Law Judge found that Berkshire's zone-gate methodology could not be employed without the concomitant use of downstream-upstream cost allocation,[57] which would more than offset the advantage to be realized by the New England customers from Berkshire's modification.

Berkshire only excepts to the rejection in the initial decision of its proposed correction of the Mcf-mile allocation method vis-a-vis Tennessee's storage,[58] portraying this rejection as violative of Section 4(a) and (b) of the Natural Gas Act: It again alleges that the New England zone is overcharged $3,000,000 annually, this overcharge constituting undue discrimination, and it moreover assails the Administrative Law Judge's apparent reliance upon "equitable considerations" which were never delineated. Berkshire also contends that this overcharge was not definitively resolved in Opinion No. 352. It furthermore be-

[57] Transmission costs for upstream customers (customers located between Tennessee's gas supply and storage) are $8.85 per 100 Mcf-miles while those for downstream customers (customers located beyond Tennessee's storage, such as the New England customers) are $22.93 per 100 Mcf-miles. (Exh. 63).

[58] Berkshire's Mcf-mile correction starts with the premise that Tennessee's system is designed on an average day basis from supply to storage and on a peak day basis from storage to those customers north and east of storage. It then reasons that the general service (G) customers, many of which are in the New England zone, are supplied by storage (less expensive than pipeline capacity) while the contract demand (CD) customers are supplied by the more expensive pipeline capacity. Finally, Berkshire would allocate more of the less expensive storage supply to these New England G customers.

littles reference in the initial decision to downstream-upstream cost allocation since this split system approach constitutes a segregation of facilities, the very methodology rejected in Opinion No. 352. Likewise, it asserts that its Mcf-mile correction is not zone-gate methodology for it applies a single principle over the entire Tennessee system: Recognition of Tennessee as a "single integrated system" allegedly remains intact for this Mcf-mile correction is defined by Berkshire as a part of functionalization, not cost allocation.

Tennessee, Staff, Northern Indiana, East Tennessee, Columbia and Consolidated, and Northern Illinois all oppose Berkshire's exception to the initial decision. First of all, they argue procedurally that Tennessee's Mcf-mile method is the same as the one approved in Opinion No. 352, that Berkshire had fully supported this allocation method in that earlier proceeding, that there have been no changed circumstances justifying Berkshire's sudden repudiation, and that the Commission therein had been aware of the impact of the Mcf-mile method upon New England but found it of no consequence because of the ameliorating effect of the use of Tennessee's system average costs (offsetting individual advantages and disadvantages). They continue by arguing substantively that Berkshire's position must be rejected for it would retain the benefits of the rolled-in system transmission costs employed in Tennessee's Mcf-mile method but at the same time identify on an *ad hoc* basis the less expensive storage capacity and segregate it for the benefit of the New England zone. They view Berkshire's proposal as at odds with the fact that storage is an integral part of Tennessee's transmission system which benefits all customers (storage permits all customers to take their contract quantity on any specific day).

We find that the Administrative Law Judge's rejection of Berkshire's several alternatives to cost allocation and

rate design should be affirmed and adopted. Berkshire's Mcf-mile correction, the only proposal it still pursues on brief, embodies zone-gate methodology in contravention of the Commission's espousal in Opinion No. 352 of the Mcf-mile method for Tennessee's zone cost allocation. To adopt Berkshire's proposal would necessitate abandoning the use of Tennessee's rolled-in system-wide transmission costs and the complete revision of the cost allocation method. The Administrative Law Judge accurately indicated, *supra* note 76, that if Tennessee were no longer treated as an integrated system using rolled-in system-wide transmission costs for allocation purposes, the New England zone would suffer a substantial increase in its allocated transmission costs which would more than offset the advantage gained from its Mcf-mile correction.

3. *Proposed Storage Rate*

Columbia and Consolidated advocated retention of the cost classification and allocation and rate design embodied in the last Tennessee rate filing settlement, *supra* note 74, which in pertinent part had "tilted" fixed costs more toward demand and away from commodity than is the case with *Seaboard* methodology as employed in Opinion No. 352. They also sought a separate storage injection rate which would save them $2.5 million annually.

The Administrative Law Judge rejected these proposals. To begin with, he refused to permit the methodology established in Opinion No. 352 to be supplanted by the subsequent settlement since the Commission therein did not treat the methods used in arriving at the ultimate dollar settlement. Moreover, he found no changed circumstances since issuance of Opinion No. 352. Finally, he found their proposed lower storage rate to provide them with a double benefit (they had been able to purchase valley gas for storage injection since 1937, thereby lowering their average cost of gas by increasing their load factor, and they

now seek a lower rate for gas to be injected into their storage).

Columbia and Consolidated except to the rejection of their proposed storage injection rate. They contend that their storage operations benefit all of Tennessee's customers, a factor recognized by the Commission as significant for rate design, *supra* note 73, and that any arguable benefit that they have received from their storage (storage has permitted them to increase their load factor and accordingly lower their unit gas purchase cost) is more than offset by their $400 million storage investment (Tr. 819). They also allege that twenty-five Tennessee customers would be eligible for this proposed storage injection rate. In conclusion they state that the rejection in the initial decision of their storage rate contravenes Commission policy to stimulate storage development.[59]

Tennessee and East Tennessee oppose this exception. To begin with, Tennessee contends that rates designed upon *Seaboard* methodology provide sufficient recognition of customer storage injection, as was the case in Opinion No. 352. Tennessee then alleges first of all that conditions have not changed since the test year underlying Opinion No. 352 so as to justify the inception of a storage injection rate and secondly that Columbia and Consolidated have gleaned substantial monetary benefit from Tennessee's two-part rate (Exh. S-12).

We find that rejection in the initial decision of Columbia and Consolidated proposed storage injection rate be affirmed and adopted. Columbia and Consolidated take deliveries from Tennessee at a very high load factor (thereby minimizing the demand charge) by injecting much of this

[59] *End Use Rate Schedules,* Docket No. RM75-19, notice of proposed rulemaking issued February 20, 1975; *Texas Eastern Transmission Corporation,* 49 FPC 594, 596 (1973); and *Natural Gas Pipeline Company of America,* 50 FPC 151 (1973).

gas into their own storage fields. Tennessee would have had to increase its peak day capacity substantially if Columbia and Consolidated had depended upon Tennessee for their peak day requirements without the assistance of storage injection. These facts which form the basis for Columbia and Consolidated's proposed special (lower) storage injection rate, as well as for their proposed tilt of Seaboard to 75/25 (more fixed costs to demand), do not warrant such proposed changes in Tennessee's cost classification, allocation and rate design. As the Administrative Law Judge accurately pointed out, these customers have been able to purchase Tennessee CD gas at a lower unit cost over the years, by utilizing their storage to attain a very high load factor, than would have been possible had they abstained from storage injection and relied upon Tennessee's peak day capacity (they would have taken gas as a much lower load factor and therefore a much higher unit cost). (Exh. 80, and S-12, pp. 15-18).

4. *Trunkline's Gas Transportation Service*

Trunkline had opposed the inclusion of the cost of storage in the rate it pays for transportation services provided by Tennessee within Louisiana. It contended that it receives no benefit in Louisiana from Tennessee's storage facilities located in New York and Pennsylvania, and it asserted that Tennessee's proposed rate increase would increase its annual cost for this transportation service by 60%.

The Administrative Law Judge rejected this proposed modification, finding that Trunkline receives from Tennessee's storage the benefit of more reliable service. He also found that allocation of storage costs on volume, not mileage, is reasonable. He characterized Trunkline's proposal as a special privilege rate which is unworkable and inequitable.

Trunkline excepts to this holding, asserting that the transportation service, rate T-11, it receives from Tennessee is unique for the service does not utilize Tennessee main line and is an exchange, not long distance transportation; therefore, T-11 deserves special treatment. Trunkline urges the Commission to allocate storage costs on the same basis as transmission costs, that is Mcf/miles and not volumetrically as is presently the case. Under the present storage allocation method a disproportionate amount of storage costs is allegedly assigned to the shortest transportation distance, that in T-11.

Tennessee and Staff oppose this exception.

We find that the Administrative Law Judge's rejection of Trunkline's proposed alteration of rate T-11 should be affirmed and adopted. Tennessee properly allocates storage costs on a system-wide or volumetric basis, instead of on a Mcf-mile basis in deriving transportation service rates, notwithstanding Trunkline's opposition. To begin with, Trunkline's allegation of a disproportionate impact of this rate increase upon T-11 is specious because T-11 was not increased in the last Tennessee rate increase settlement, *supra* note 54. Moreover, the Commission was correct in Opinion No. 352 to approve storage cost allocation upon a system-wide basis: Tennessee's storage improves reliability and reduces system-wide transmission costs; therefore, Trunkline benefits from Tennessee's storage facilities even through it is not physically dependent upon their services. Finally, Trunkline, like Berkshire, seeks to retain the benefits accruing from cost allocation premised upon treating Tennessee as an integrated pipeline system but at the same time espouse *ad hoc* segregation of facilities when advantageous. Such an approach must be rejected as being inequitable and deficient in record support when contrasted with the Commission's comprehensive cost allocation in Opinion No. 352, which is still dispositive of this issue.

The Commission further finds:

(1) Applicant, Tennessee Gas Pipeline Company, is a "natural gas company" subject to the provisions of the Natural Gas Act (Act), and the sales of natural gas subject to the order which follows as a part of this decision are sales of natural gas in interstate commerce for resale subject to the jurisdiction of the Commission.

(2) Applicant's rates, which have been in effect in this docket subject to refund have not been shown to be just and reasonable or otherwise lawful under the provisions of the Natural Gas Act, in the respects noted above, and Applicant should be required to file just and reasonable rates as necessary to conform to this opinion and order.

(3) Applicant should be required to refund to its jurisdictional customers any amounts reflecting the difference between its proposed rates and the rates required to be filed by this opinion and order.

(4) The initial decision issued in this proceeding on February 3, 1975, should be affirmed in part and reversed in part as hereinabove detailed.

The Commission orders:

(A) The increased rates referred to in Paragraph (2) above, are disallowed to the extent they do not conform to this opinion and order.

(B) Within 60 days of the issuance of this opinion and order, Applicant shall file any necessary amendments to its cost of service, classification and allocation of costs and tariff sheets for the period from January 1, 1974, to March 16, 1975, subject to the approval of the Commission.

(C) Within 30 days of the Commission's approval of its substitute tariff sheets in accordance with (B) above, applicant shall refund to its customers for the January 1, 1974, to March 16, 1975, period all amounts, if any, collected in

excess of those which have been payable under the rates and charges approved in accordance with (B) above, together with interest at the rate of seven percent per annum from the date of payment to Applicant to the date of refund for the period of January 1, 1974, to October 10, 1974, and with interest at the rate of nine percent per annum for the period from October 10, 1974, through March 16, 1975.

(D) Within 30 days after making the refunds required by Paragraph (C), Applicant shall file with the Commission, in writing and under oath, a report as to the amount of any refunds made and its method of computing the same, together with releases from its jurisdictional customers.

(E) The initial decision of the Presiding Administrative Law Judge issued February 3, 1975, is adopted as the decision of the Commission to the extent not inconsistent herewith.

(F) Exceptions not granted are denied.

By the Commission. Commissioner Smith, concurring filed a separate statement appended hereto.

(SEAL)

Commissioner Holloman, dissenting, filed a separate statement appended hereto.

Kenneth F. Plumb,
Secretary.

TENNESSEE GAS PIPELINE COMPANY

Docket No. RP73-113

SMITH, Commissioner, *concurring*:

(Issued July 9, 1976)

Although I concur that the overall rates here allowed are "just and reasonable", I cannot agree with the majority's method in reaching this result. The majority's traumatic but necessary excision of Tennessee's front-end advances does not justify its largesse in allowing a 13.75% return on common equity. It is the erroneous attempt to support the equity return on other grounds that I find objectionable.

The allowance of 13.75% return on common equity should not be justified by comparison with other similarly situated companies. Although there is no specific formula or formulae for determining, with absolute precision, the appropriate rate of return, the result reached by the Commission must be supported by ample record evidence and must fall within a "zone of reasonableness". Unfortunately, the majority opinion falls far short of this goal.

A cursory examination of the opinion reveals its deficiencies. Its first premise is that Tennessee's need for new capital ". . . will require a much higher proportion of future financing through new issues of equity capital, because of interest coverage restrictions." (Op. at 12.) This statement may be true, but it leaves certain important questions unanswered. How much of this capital can be internally generated? Is there a serious erosion of investor confidence in Tenneco's securities that can *only* be restored through allowance of 13.75% return on common equity? What are the interest coverage restrictions since the record demonstrates that Tenneco's interest coverage is between 2.82 and 2.85?

The opinion next considers, and gives great weight to, three forms of risk to Tennessee which supposedly justify the 13.75%. These are financial, interest rate and purchas-

ing power risk. The majority evaluates these risks by noting, through various exhibits, the historic rise of bond yields, yields in the equity market and the wholesale and consumer price indices. The majority then examines the ratings accorded the securities of the electric utilities, industrials, distribution and transmission companies and, on the basis of all this, generally concludes that transmission companies are more risky than other companies, that as embedded debt costs increase higher returns on equity must be afforded, and that inflation impacts on the cost of equity. There is no attempt to relate these generalities to the pipeline involved and the record in the instant proceedings.[1]

The majority concludes by discussing the comparable earnings and capital attraction tests. In discussing comparable earnings, the majority again generalizes and apparently reaches no conclusion. In discussing capital attraction, the majority states that "... the record contains only sparse evidence with which to gauge the capital attraction of utilities and more specifically natural gas transmission companies." (Op. at 22.) Based upon these generalizations, the majority reaches the end result, *i.e.* 13.75%. Unfortunately, the majority has chosen to ignore even this "sparse evidence" and does not attempt to give adequate recognition to the facts at hand.

Just recently, the Commission had an opportunity to decide the appropriate rate of return for Natural Gas Pipeline Company of America.[2] There the Commission enumerated numerous factors which justified the return

[1] The only discussion relating to Tennessee is a chart which demonstrates that Tenneco's cost of embedded debt has increased, as is the case with all pipelines, since 1960.

[2] *See,* "Opinion And Order Approving Settlement With Conditions And Determining Reserved Issues", *Natural Gas Pipeline Company of America,* Docket No. RP74-96, Opinion No. 762, issued May 21, 1976.

on common equity allowed, 13.5% A comparison of that Opinion and the majority's discussion in the instant case shows the deficiencies of the latter. In *Natural, supra,* significant weight was attached to the deteriorating gas supply situation in general and Natural's specific supply problems.[3] A very important consideration therein was Natural's reserve life index which dropped from 18 in 1963 to 9.6 in 1973, and to 9.1 by 1974. In contrast, Tennessee's reserve life index was 20 in 1962, 7.4 in 1973, but rose to 10.8 in 1974.[4] Another important consideration in *Natural, supra,* was the fact that People's bonds were derated from Aa to A, and its debentures were derated from A to Baa. In 1971, Tenneco's bonds were upgraded to A from Baa, and its debentures from Ba to Baa, ratings which are still in force.[5] Another interesting comparison between the instant proceeding and *Natural, supra,* is the embedded cost. The majority placed great emphasis on the historic rise, in this cost to Tennessee and noted that at the end of 1972 the embedded debt cost to Tennessee was 6.57%, a 54% increase since 1960. In comparison, People's cost of embedded debt stood at 7.37% in 1974, an increase of more than 83% since 1958.[6] Going further, a comparison of the market to book ratios for Peoples and Tenneco reveals that, during approximately the same period of time,

[3] The Commission has, in other proceedings, indicated that the present gas supply situation is a major factor in determining rate of return. *See,* Opinion No. 731, *Kansas Nebrasks Natural Gas Company,* Docket No. RP72-32, issued May 15, 1975.

[4] By 1973, the nationwide reserve-life index declined to 9.7 years.

[5] Presumably, these ratings did not ignore Tennessee's gas supply situation and Tennessee's impact on the operations of Tenneco since during the test year Tennessee's reserves comprised 40% of Tenneco's income. (Ex. S-5).)

[6] In February 1975, Peoples sold 60 million dollars of 20 year bonds at an effective cost of $9.49%. In January 1974, Tenneco marketed 100 million dollars of debentures at an effective cost of 9.15%.

Tenneco's M/B ratio ranged between .86 to 1.07 while Peoples' M/B ratio never went above .96.

Other factors which were not given adequate recognition by the majority relate to Tenneco's earnings and dividends, its equity ratio and its interest coverage. Tenneco's earnings and dividends per share have increased every year since 1965. Its equity ratio, which stood at 31% in 1965, had increased to approximately 40% by 1973. Finally, as noted earlier, the record demonstrates that Tenneco's earnings have been in the range of 2.82 to 2.85 times its long-term interest obligations. These financial benchmarks are of great importance in determining the fair rate of return and reasoned consideration should be given to these factors. The *Natural* Order, *supra,* should be regarded as a reasoned assessment of the record in that case, not a new rate of return floor. In my opinion, such consideration is lacking in the majority's opinion for the return allowed is more than necessary to "assure confidence in the financial soundness of the utility . . ." and is more than is necessary "to maintain and support [Tenneco's] credit and enable it to raise the money necessary for the proper discharge of its public duties." [7] Any return such as that allowed by the majority which is more than necessary for the company to maintain financial integrity, attract capital, and adequately compensate its investors for assumed risks has not met its statutory obligation to balance both investor and consumer risks.[8] The overall result here reached is supportable only because of the treatment given advance payments.

/s/ Don S. Smith
Don S. Smith,
Commissioner

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[7] *Bluefield Water Works and Improvement Co.* v. *Public Service Commission of West Virginia,* 262 U.S. 679 (1923).

[8] See, *F.P.C.* v. *Hope Natural Gas Company,* 320 U.S. 591 (1944).

Tennessee Gas Pipeline Company

(A Division of Tenneco, Inc.)

Holloman, Commissioner, *dissenting:*

(Issued July 9, 1976)

The majority states that " . . . though there is no specific prohibition against front-end advances, such a prohibition is implicit in the 'reasonable and appropriate' standard of that order". Not only is there nothing in the reasonable and appropriate standard which would imply that front-end advances are unlawful *per se,* but there is evidence in this proceeding supporting Tennessee's contention that its advances were both reasonable and appropriate. Since the Commission had not promulgated any express restriction on the timing of a pipeline advance as it relates to the timing of the producer's expenditure, it was reasonable for the parties to assume that this was a matter free for negotiation, though still to be subject to the test of "reasonableness". Past Commission acceptance of front-end advances based upon the facts and special circumstances indicates that the Commission itself had intended this to be the rule.[1] It now behooves the Commission to examine the record and apply the "reasonable and appropriate" standard to the facts of this case.

It is clear that Tennessee's front-end advances were neither extravagant nor unnecessary. The front-end advances originally challenged by the Commission Staff were related to offshore production. They are consistent with the common business practices which the Commission's own advance payment orders have fostered.[2] Investigation

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[1] *Columbia Gas Transmission Corporation,* Docket Nos. RP71-18, *et al.,* Opinion No. 722, issued March 7, 1975.

[2] See attached appendix.

of the Commission's records indicate that virtually every offshore pipeline in the Nation has made front-end advances pursuant to the Commission's orders. The overwhelming preponderance of dollars advanced pursuant to Order No. 465 were front-end advances. In addition to its orders promulgating and continuing the advance payment program, the Commission has had the opportunity to adopt a temporal restriction to be applied, but chose not to do so, and instead looked to the circumstances of the case and allowed the front-end advances.[3] A pipeline such as Tennessee faced with this competitive climate would be remiss in its attempts to attach new supplies of gas on behalf of itself and its customers if it did not use this tool to enter into new gas supply contracts. Tennessee's witness Shivers testified that such advances were absolutely necessary for the company to obtain commitments by producers. (T-12, p. 11-14.) Even more convincing is the testimony of witness Brennand who actively negotiated with pipelines for advances on behalf of producers. Not only does he point out that other pipelines were offering front-end advances to compete for dwindling gas supplies, but that producers would be willing to arrange their *own* financing on an installment basis rather than undertake disadvantageous commitments which waive future options as required by advance payment agreements. (T-13, pp. 2-6, Exh. 70) Indeed, Mr. Brennand points out that producers filed front-end advance contracts with this Commission prior to its issuance of Order No. 465 which extended the advance payment program without expressing dissatisfaction with such arrangements. (T-13, p. 2.) In fact, the instant case is the first in which Staff advocated its thirty-day rule.

The evidence in this proceeding also sets forth several positive factors to be weighed on the side of front-end advances. Typically, under the installment approach pro-

[3] *Columbia, infra.*

posed by the majority, the risks of increased costs, whether from inflation, human error or natural disaster, rest with the pipeline, whereas with front-end advances the risk is borne by the producer. (T-12, p. 13.) Not only can this result in the front-end advance actually being *lower* than installment advances, but it also guarantees a degree of certainty to the pipeline's need for capital, which can result in a lower cost of capital for the pipeline and greater flexibility for the company to plan other supplemental gas activities. Tennessee also points out that the front-end advance also allows it to obtain a commitment of an entire lease rather than the well-by-well commitment allowed by the installment method.

The record in this case also indicates that the ultimate consumer will not have to bear the cost of advances which are never utilized by the producers. Had this not been the case, I would have Tennessee refund to its jurisdictional customers the carrying charges attributable to any amount of front-end advances which are not actually spent by the recipient producers on exploration, development or production. I would also point out that I would not approve all front-end advances merely because they were the result of arms-length negotiations between producer and pipeline. The record in each proceeding should be weighed and the agreements examined to ascertain whether the amounts to be advanced are reasonable; the lead time provided for is not inconsistent with common business practices; and the benefits to the pipeline so deficient on balance, as to make the advances inconsistent with the "reasonable and appropriate" standard.

Advances to Affiliated Producers:

I would reverse the Presiding Judge's disallowance of unexpended advance payments to affiliated producers. Order No. 465, under which the subject advance payment agreements were promulgated, states that "[f]or rate base

purposes advances to pipeline affiliated producers shall be treated he same as advances to independent producers."[4]

Upon analysis of the specific record facts in this proceeding it is clear that all of Tennessee's advance payments to non-Canadian affiliated producers were reasonable and appropriate. The Administrative Law Judge misplaced his emphasis upon the timing of when the advances were made (within 30 days), the unexpended nature of a substantial portion of these advances, and the failure to segregate them into a separate account. There is no indication from the record that in the advance payment negotitions between Tennessee and Tenneco Oil Company their affiliation impeded an otherwise objective and good faith bargain. (Tr. 356, 498-500, 113.) A pipeline cannot be criticized for timing an advance payment such that it falls within the test period of a rate filing to insure the very rate treatment which the Commission itself intended and authorized. Furthermore, there is uncontradicted evidence from the Staff witness that the advances made to the affiliated producer were good faith agreements on the part of Tennessee and that there were no significant differences between these advances and those to independent producers. In light of these facts, I find it unnecessary to reverse stated Commission policy.

Rate of Return

I would affirm the Presiding Judge in his rate of return determination for the reasons set forth in his Initial Decision.

/s/ JOHN H. HOLLOMAN III
John H. Holloman III
Vice Chairman

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[4] Accounting and Rate Treatment of Advance Payments Included in Account 166, Advance Payments for Gas Development and Production, Docket No. R-411, Order No. 465, issued December 29, 1972, 48 FPC 1550, 52.

LIST OF CASES REFLECTING FRONT-END ADVANCES

Pipeline Company	*Docket Number*
Arkansas Louisiana Gas Company	RP76-10
Colorado Interstate Gas Company	RP74-77 RP75-86
Columbia Gas Transmission Corporation	RP74-82 RP75-106
Consolidated Gas Supply Corporation	RP73-107 RP74-90 RP75-91
Kansas-Nebraska Natural Gas Company, Incorporated	RP74-11 RP76-8
Michigan Wisconsin Pipe Line Company	RP73-102 RP75-96
Natural Gas Pipeline Company of America	RP72-132 RP73-110 RP74-96 RP75-108
Northern Natural Gas Company	RP75-89
Panhandle Eastern Pipe Line Company	RP73-108 RP75-102
Southern Natural Gas Company	RP72-91 RP75-84
Tennessee Gas Pipeline Company	RP73-113 RP75-13 RP75-113
Texas Eastern Transmission Corporation	RP72-98 RP74-41 RP75-73

Pipeline Company	*Docket Number*
Texas Gas Transmission Corporation	RP75-19 RP76-17
Transcontinental Gas Pipe Line Corporation	RP74-48 RP75-3 RP75-75
Transwestern Pipeline Company	RP75-74
Trunkline Gas Company	RP72-23 RP74-89
United Gas Pipeline Company	RP74-20 RP74-83 RP75-30 RP75-109

APPENDIX C

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Opinion No. 769-A

Before Commissioners:

Richard L. Dunham, Chairman;
Don S. Smith, John H. Holloman III,
and James G. Watt.

TENNESSEE GAS PIPELINE COMPANY

(A Division of Tenneco, Inc.)

Docket No. RP73-113

OPINION AND ORDER DENYING REHEARING

(Issued May 31, 1977)

On July 9, 1976, the Commission issued Opinion No. 769 establishing just and reasonable pipeline rates for Tennessee Gas Pipeline Company (Tennessee). Applications for rehearing of portions of Opinion No. 769 were filed on August 6, 1976, by Berkshire Gas Company, *et al.* (Berkshire), and Trunkline Gas Company (Trunkline); on August 6, 1976, by Tennessee, Interstate Natural Gas Association of America (INGAA) which simultaneously petitions to intervene), Transcontinental Gas Pipe Line Corporation (Transco) (which simultaneously petitions to intervene), Columbia Gas Transmission Corporation and Consolidated Gas Supply Corporation, (Columbia and Consolidated) and Brooklyn Union Gas Company (Brooklyn); and on August 10, 1976, by the Public Service Commission of the State of New York (PSCNY). Also on August 9, 1976, Tennessee and INGAA filed motions for

oral argument of the front-end advance payment issue in Opinion No. 769. By order of September 3, 1976, we granted rehearing for purposes of further consideration, denied the motions for oral argument, and granted untimely petitions to intervene.

I. ADVANCE PAYMENTS

(A) Front End Advances

Tennessee, Transco, INGAA, Trunkline and PSCNY all seek rehearing of the Commission exclusion of some $92,000,000 of front-end advance payments which had not been expended by the recipient producers by the effective date of the proposed rates. Numerous grounds are advanced.

Tennessee begins its assault upon the "line of credit" test referred to in Opinion No. 769 by contending that this test conflicts with the "reasonable and appropriate" standard extant not only in the applicable advance payment order, Order No. 465, but also its predecessors.[1] It then adds that the standard is "reasonable and appropriate in order to obtain commitments for additional gas supplies." Tennessee then details the contents of these several advance payment orders in order to emphasize the absence of any express "line of credit" time limitation upon the disbursement of advance payments. It moreover advances case authority[2] which allegedly supports its contention

[1] Order No. 465, 48 FPC 1550 (1972); Order No. 441, 46 FPC 1178 (1971); Order No. 410-A, 45 FPC 135 (1971); and Order No. 410, 44 FPC 1142 (1970).

[2] *Columbia Gas Transmission Corporation* (Advance Payment Getty), Opinion No. 722, Docket Nos. RP71-18, *et al.*, issued March 7, 1975, *aff'g Columbia Gas Transmission Corporation*, Docket Nos. RP71-18, *et al.*, initial decision issued January 18, 1974; *Trunkline Gas Company*, Docket Nos. RP72-23, *et al.*, initial decision issued November 13, 1974; *Transcontinental Gas Pipe Line Corporation*, Docket Nos. RP74-48, *et al.*, initial decision

that the "reasonable and appropriate" standard of Order Nos. 410, 410-A, 441, and 465 does not encompass the "line of credit" test adopted in Opinion No. 769.

Tennessee, joined by INGAA, then advance what appears to be an estoppel argument; that is, they allege that from various sources[3] the Commission had knowledge of the wide-spread existence of front-end advances but chose to take no action against them until Opinion No. 769. They infer from this alleged pre-Order No. 465 Commission knowledge of the existence of front-end advances and the absence of language in Order No. 465 specifically excluding such advances that the Commission could not have intended the "reasonable and appropriate" standard to encompass the "line-of-credit" standard.

Tennessee next turns to the most recent advance payment order, Order No. 499,[4] and asserts that the Commission's general policy stated therein (to exclude advances not expended by the recipient producer "within a reasonable time from the date such amounts advanced are included in the pipeline a rate base") necessarily indicates that there was no such policy intended in Order No. 465. Tennessee, supported by INGAA, concludes this particular basis for rehearing by arguing that the Commission in Opinion No. 769 violated due process by retroactively ap-

issued December 22, 1975; *Michigan Wisconsin Pipe Line Company*, Docket Nos. RP73-102, *et al.*, initial decision issued March 31, 1975.

[3] 1) The position taken by PSCNY against front-end advances in several proceedings; 2) Data contained in Attachment D to Order No. 465; 3) Data contained in FPC Form 102 reports on file with the Commission (summarized in Exh. 72); 4) Commission rejection in Order No. 465 (48 FPC at 1552 of a proposed "per Mcf cost" for reserves attached under the program; 5) FPC Office of General Counsel statement delivered to Federal Power Bar Association on April 29, 1971.

[4] 50 FPC 2111 (1973).

plying this new timing standard first enunciated in Order No. 499 to the instant proceeding governed by the prior Order No. 465.

Tennessee then recites its evidentiary presentation on this issue (Exh. T-12, T-13) to support a finding that its front-end advance payments are "reasonable and appropriate" under its interpretation of Order No. 465. Specifically, it points to evidence showing that front-end advances were common business practice, of benefit to its customers, made by Tennessee in good faith, and an absolute term of trade which the producers could insist upon because of their superior bargaining position. Tennessee, INGAA, Transco and PSCNY stress the importance of this latter point, that competitive pressures forced Tennessee to make front-end advance payments, as is allegedly recognized by the Commission in Opinion No. 722, *supra* note 2.

The other parties seeking rehearing of our exclusion from rate base of Tennessee's front-end advance payments come forward with numerous theories. Transco and INGAA suggest that the Commission erred by founding the timing test upon how a producer finances exploration and development. Instead, they contend that the relevant inquiry is how a pipeline would finance its advance payments, and that from the pipeline financing perspective Staff's thirty-day rule is clearly wrong for a pipeline will finance advances in part through equity and long-term debt securities, which cannot be used to raise capital in such a short period, and in part through bank borrowings, which often require commitment fees or maintenance of compensating balances. As a related matter INGAA also contends that there was no substantial evidence supporting application of the "line of credit" thirty day rule to producers. It discounts Staff's presentation on the subject, and it moreover alleges that producers, like pipelines mentioned above, rely heavily upon equity and long-term debt securities, which cannot be marketed in installment quan-

tities and on thirty days notice, as well as bank loans requiring commitment fees or compensating balances.

Transco continues with several more contentions. To begin with, it points out that Opinion No. 769, by adopting a per se rule (front-end advances are presumptively extravagent) conflicts with the Commission's prior position that it would judge the reasonableness and appropriateness of advance payments on a case-by-case basis. Transco furthermore reasons that the "line of credit" standard is anathema to the underlying purpose of the advance payment program, which is to provide an extra incentive or stimulus to producers. Finally, Transco propounds that the "line of credit" standard equates to interest reimbursement, which the Commission has already rejected.

We find that rehearing of Opinion No. 769 as to our exclusion of front-end advance payments from rate base should be denied. Accordingly, we continue to exclude such advances for they have not been shown to be reasonable and appropriate.

Tennessee contends that, by imposing the "line of credit" standard upon its Order No. 465 advance payments, the Commission went beyond the "reasonable and appropriate" standard of Order No. 465 or its predecessors; however, this is clearly not the case. Every time a pipeline seeks to increase its jurisdictional rates Section 4(e) of the Natural Gas Act mandates that it prove that such increase is just and reasonable. This burden of proof governs Tennessee's actions notwithstanding the specific language of any Commission rulemaking order. In the present context, however, the Commission has expressly forewarned the interstate pipelines that only "reasonable and appropriate" advances will be permitted in rate base. If advances which are front-end in nature are in fact unreasonable and inappropriate, then it is difficult to understand how the Commission is precluded from enforcing the express "reasonable and appropriate" standard. The several

specific criteria placed in the advance payment orders up to and including Order No. 465 [5] were intended to address particular details of the program which might not be conclusively resolved in the "reasonable and appropriate" standard. Since, as we shall elaborate upon subsequently, a substantial time lag between when the pipeline advances funds to the producer and when the producer actually expends such funds has no inherent justification, there was no need to specifically identify the problem. It cannot be argued that the Commission's rate jurisdiction under Sections 4 and 5 of the Natural Gas Act is limited to those items specifically and previously stated in a rulemaking or adjudicatory order, even though the rate increase item at issue is nonetheless unreasonable and inappropriate. Moreover, Tennessee's insistence upon language in Order No. 441 ("reasonable, necessary and appropriate in order to contract for gas supplies") is misplaced for that language refers to the underlying justification for the entire advance payment program.

The Commission did not establish a new standard in Opinion No. 769. Instead, it applied the existing "reasonable and appropriate" test. The "reasonable and appropriate" standard predates Order No. 465. It was also found in Orders Nos. 410, 410-A and 441; however, this standard was never interpreted by the Commission to tolerate front-end advance payments, Tennessee's allegations to the contrary notwithstanding. Advance payment timing was not mentioned in Order No. 465 because there was no apparent need to alter the "reasonable and appropriate" standard, which already contemplated the exclusion of extravagant and unnecessary expenditures. In addition as early as September 1974, the Commission had explicitly stated

[5] Inclusion of producer costs for exploration; five year period from inclusion in rate base until commencement of gas deliveries; five year repayment period; inclusion of advance payments to affiliate producers; continued exclusion of lease acquisitions.

that the "reasonable and appropriate" standard in Order No. 465 encompasses a reasonable timing test.[6]

The issue of the reasonableness of front-end advances was clearly raised in this proceeding by Staff's direct case for the thirty day rule. (Exh. S-10, and 49). Tennessee had the opportunity to rebut the thirty day rule but chose instead to ague as a matter of law that Order No. 465 contemplated front-end advances, (Exh. T-12) and as a matter of fact that the producers would not have been as inclined to enter advance payment agreements absent the front-end "incentive." (Exh. T-13). Staff raised serious questions as to the reasonableness of Tennessee advancing large sums to producers which did not plan to use them for a period of months or years. While we do not find that a maximum time lag of thirty days between advance and expenditure is necessarily the only reasonable and appropriate standard, it was well pleaded and completely unrebutted by Tennessee. Accordingly, we find that Tennessee failed to meet its burden of proof that its front-end advance payments were reasonable and appropriate.

It might be that Tennessee requires more or less time in order to make available the funds needed by the recipient producer for specific expenditures; however, Tennessee was silent on this point which was clearly at issue. Staff pointed out (Exh. S-9, p. 6) that on the average Tennessee's front-end advances were not fully utilized by the recipient producers for 22.8 months. Although in specific cases it might be reasonable to expect that the pipeline needs more than thirty days to respond to a producer's request for funds for imminent exploration, development or production activity, we can conclude from our regula-

[6] *Natural Gas Pipeline Company of America*, 52 FPC 652, 655 (1974). The Commission therein stated in regard to Order No. 465 that "[o]ur intent has been that the actual advance of funds would closely approximate the operation of a line-of-credit, *i.e.*, the funds would be drawn down as cost and progress required."

tory experience that no company would ever attract capital as far in advance of expenditure as Tennessee has allowed its recipient producers to do in this case. It would be unjust and unreasonable to saddle Tennessee's customers with the carrying charges of such extravagant financial arrangements.

It must be remembered that the entire advance payment program was a sharp departure from traditional producer regulation. Although the program was "a justifiable experiment in the continuing search for solutions to our nation's critical shortage of natural gas,"[7] the unique nature and obvious impact upon the pipelines' customers of the program have required throughout close scrutiny of the associated costs. Under such circumstances it seems incredible that any pipeline would have advanced large sums to producers many months or years before those producers planned to expend them.

Moreover, Tennessee's allegations of Commission knowledge of the existence of substantial front-end advances prior to its promulgation of Order No. 465, *supra* note 3, is not only unfounded but also inappropriate. Tennessee is asking the Commission to first of all infer from statistical data and other material, patent evidence of massive front-end advances and secondly to assume the responsi-

[7] *Public Service Commission of New York* v. *FPC*, 467 F.2d 361, 371 (D.C. Cir. 1972). Of course pursuant to the court remand in *Public Service Commission of New York* v. *FPC*, 511 F.2d 338 (D.C. Cir. 1975) the Commission has subsequently reassessed the program and has determined that the advance payment program should be terminated. *Advances for Gas Exploration, Development and Production*, Docket Nos. R-411 and RM74-4, orders issued December 31, 1975, and February 27, 1976. In addition the Commission has more recently required a reduction in the charge paid by a pipeline to a producer under the new national rate for the carrying charges for any advances made after November 5, 1976. Opinion No. 770-A, Docket No. RM75-14, issued November 5, 1976.

bility for amending its advance payment regulations to explicitly address this at best inferred problem with the penalty for nonfeasance (excessive and unnecessary carrying charges) imposed upon the consumer. Tennessee's estoppel argument conflicts with the mandate of the Natural Gas Act and cannot prevail. In addition it is factually unfounded.

The alleged sources and indications of Commission knowledge of pre-Order No. 465 front-end advance payments, *supra* note 3, are inadequate under any standard. To begin with, PSCNY's comments to the notice of rulemaking preceding Order No. 465, as well as its application for rehearing of Order No. 465, both cited by Tennessee, indicate a general concern for the relative inequality of bargaining positions between producers and pipelines and a desire for greater standards to be imposed upon advances, noting that "possibly they could be tied to specific cost expenditures." While one could possibly infer from this that PSCNY was concerned over front-end advances, such an inference is by no means obvious or even likely.

In addition, the advance payment data presented in both Attachment D to Order No. 465 and FPC Forms 102 does not afford a patent demonstration of wide-spread front-end advances prior to Order No. 465. The Commission employed Attachment D in Order No. 465 to demonstrate that the advance payment program had resulted in significant production activity, including the addition of substantial proven reserves. Under Tennessee's argument, the Commission would now have to waive the protection of the Natural Gas Act as to Tennessee's customers for any otherwise "unreasonable and inappropriate" advances of the type which might conceivably be inferred to exist from some statistical data used by the Commission for a totally different purpose.

Furthermore, Tennessee's reference to Commission rejection in Order No. 465 (48 FPC at 1552) of the proposal

to determine a charge per Mcf by dividing dollars advanced by total reserves reported is inapposite as to the instant factual issue. It is clear from the Commission's reasoning therein that recognition of front-end advances was not one of the bases for rejecting the proposal. The remainder of the alleged sources (General Counsel statement) is too attenuated to warrant any reply.

We are similarly unpersuaded by the legal precedent cited, *supra* note 2. Except for Opinion No. 722, initial decisions alone are being called upon. The Commission is obviously not bound by the ruling of an Administrative Law Judge if it finds that the initial decision is erroneous as a matter of law or fact. In addition Opinion No. 722 does not support Tennessee's stance. Even a cursory reading of that order indicates that the Commission approved of the timing concept being implicit in the "reasonable and appropriate" standard,[8] and the inclusion of certain front-end advances therein was expressly limited to the facts.[9] To the extent, however, that Opinion No. 722 could conceivably be read as Commission sanction of rate base inclusion for front-end advances which have not been shown to be reasonable and appropriate, it is hereby overruled and shall not be followed in any Commission decision. Such rejection of the holding in Opinion No. 722 in no way prejudices Tennessee since its issuance date of March 7, 1975, follows the end of the adjusted test period in RP73-113.

We turn to Tennessee's argument that a timing standard to be applied to front-end advances was not promulgated until Order No. 499 and that accordingly its retro-

[8] "We agree with Staff that there must be a reasonable and appropriate relationship between the amount and time of advance and the amount and time of their utilization." (Slip op. at 8).

[9] "Our action herein should not be interpreted to mean that in any future cases the reasonable and appropriate standards as discussed above will be waived." (Slip op. at 9).

active application to advances made pursuant to the earlier Order No. 465 violates due process. Opinion No. 769 does not run afoul of the proscription against retroactive rulemaking because, as we have already demonstrated above, the "reasonable and appropriate" standard, extant through all of the advance payment rulemaking orders, necessarily covered such unnecessary and extravagant costs as those resulting from front-end advances. Of course the Commission did explicitly impose the timing standard in Order No. 499; however, this was no change in policy. It was instead due to the Commission's realization that the pipelines were disregarding the "reasonable and appropriate" standard of Order No. 465 and that its intention had to be further delineated.

Neither can the Commission find an adequate basis for including these front-end advances from Tennessee's evidentiary presentation (Exh. T-12, T-13), as we have already concluded in Opinion No. 769. Although we would include in rate base front-end advances made under agreements for which the terms and conditions produced a positive or net benefit has been made by Tennessee. An example of such positive benefit is found in *Transcontinental Gas Pipeline Corporation*, Opinion No. , Docket Nos. RP74-48 and RP75-3, issued on this day.

Through the conclusory statements of its witnesses Tennessee attempts to prove that its front-end advances are reasonable and appropriate for the following reasons: (1) Tennessee made a good faith effort to comply with Order No. 465 as it understood that order. (Exh. T-12, pp. 2-10). (2) It was reasonable to make front-end advances under Order No. 465 because so many advances were being made in that format at that time. (Exh. T-12, p. 11). (3) The producers insisted upon front-end advances; therefore, Tennessee could not have formed any advance payment contracts but for the front-end feature. (Exh. T-12, pp. 11-12; Exh. T-13, pp. 3-6). (4) Front-end

advances benefit the consumer for they commit gas reserves at a lower cost than installment advances for the latter are subject to cost escalation. (Exh. T-12, p. 13; Exh. T-13, p. 6). (5) Front-end advances also benefit the consumer by creating financial certainty for the pipeline which is translated into rate stability. (Exh. T-12, p. 13). (6) Front-end advances moreover benefit the consumer by promoting more rapid exploration and development and tying attachment of onshore reserves to offshore reserves. (Exh. T-12, p. 13-14; Exh. T-13, pp. 6-7). Not only is the aforementioned evidence of limited value because it is merely conclusory statements, but it is also in large part incorrect.

All of the arguments made in favor of front-end advances tactfully avoid the central fact that, while Order No. 465 permits rate base treatment for advances used for gas exploration, development and production, Tennessee's front-end advances were used by the producers for a substantial time period for other purposes. As we have already stated, a pipeline might be able to show that it needs more than thirty days to finance its advances upon request by the producer; however, to merely advance the recipient producer large sums of money, long before that producer would under common business practice obtain liquid funds and long before it intended to expend such sums, is necessarily unreasonable and inappropriate. While Tennessee *now* bemoans the competitive situation (front-end advances were a necessary term of trade) in which it found itself in 1973, it should have apprised the Commission of the problem at that time instead of participating in this unreasonable and inappropriate contractual arrangement. Moreover, the Commission cannot surrender the rights of the consumer when a number of pipelines, as in the present case, decided to make excessive advances and as a result made the front-end feature a required condition of advance payment bargaining.

We conclude by addressing the arguments presented by the other parties seeking rehearing. To begin with, a determination of reasonableness and appropriateness requires consideration of the common business practices of producers; however, we would have also considered evidence by the pipeline as to how it could reasonably finance its installment payments to the producers for specific expenditures. In other words a pipeline might be able to show that thirty days is too short. Unfortunately, Tennessee declined to make such a presentation and must now stand upon its silence. The burden of proof was upon Tennessee to rebut the thirty day rule and it ignored the burden. In this case, we do, however, exclude from rate base any advances made by Tennessee which had not been expended by the recipient producer within thirty days after the end of the nine month adjusted test period. In addition we reject the contention that the Commission has ignored its prior pronouncements of avoiding a per se stance and adopting a case by case approach. Since we have applied the reasonable and appropriate standard to the specific facts of this case, as is evident from the discussion above, it is clear that the Commission has not taken a per se view of these front-end advances. Furthermore, the incentive purpose of the advance payment program is manifested in allowing the producers consumer-financed, interest-free loans for exploration, development and production expenditures. Although the producers would obviously be further enriched by interest-free loans for any other purpose, as would result from front-end advances, this added incentive imposes excessive and unreasonable costs upon the consumer. Finally, the Commission's rejection of interest reimbursement schemes[10] does not govern the installment advance concept approved

[10] *e.g., United Gas Pipe Line Corporation,* Docket No. RP75-50, order issued September 4, 1975; and *Transcontinental Gas Pipe Line Corporation,* Docket No. RP75-75, issued September 9, 1975.

herein. Limiting rate base treatment to advances made within a reasonable time of expenditure does not equate to interest reimbursemnt. This is because a producer, which has not been able to attract sufficient capital for exploration, development and production, should be able to finance its expenditures through an advance payment arrangement contemplating installment, not front-end, advances.

(B) Advances to Affiliate Producers

Tennessee also seeks rehearing of the Commission's affirmance of the exclusion from rate base in the initial decision of non-Canadian, unexpended, intracorporate advance payments. It prefaces its argument with its prior conclusion that front-end advances are permissible under Order No. 465. It then argues that, if the Commission in Opinion No. 769 affirmed the rationale found in the initial decision, it has committed error for Order No. 465 clearly states that advances to affiliated and independent producers shall receive the same treatment.

We deny rehearing of our exclusion of Tennessee's non-Canadian, unexpended, intracorporate advances. We do so, however, solely for the same reason that we excluded front-end advances, but in the context of the initial decision the Administrative Law Judge erred by treating affiliated and independent producers differently. He failed to follow our pronouncement in Order No. 465 that "[f]or rate base purposes advances to pipeline affiliated producers shall be treated the same as advances to independent producers."

(C) Canadian Advances

Tennessee moreover seeks rehearing of the Commission's exclusion from rate base of $37,500,000 of advance payments made to Tenneco Oil and Mineral Limited for exploration and development in the Arctic Islands area

of Canada. It assigns error first of all to the alleged Commission failure to consider its evidence of requisite Canadian assurances of export authorization and secondly to the Commission's limited consideration of extra-record material concerning Canadian export policy in that the Commission failed to consider other material which Tennessee cites for the first time herein.

Tennessee prefaces this rehearing petition by noting for the first time that it would accept a condition requiring refund of all carrying charges related to this Canadian advance if Canada ultimately declined to authorize exportation of this Arctic Island gas to Tennessee. It then attacks the exclusion of its Canadian advances by first relying upon its evidentiary presentation below (Exh. T-14) to prove that export authorization for this Arctic Island gas will occur. It reiterates its position that under the Canadian National Energy Board's (NEB) export test (there must be a surplus of reserves over 25 times the level of Canadian demand four years in the future) the 34.2 Tcf threshold has been more than met by the 60 Tcf reserves estimates, which do not include a possible 30 Tcf from the Arctic Islands, as well as additional reserves from the other frontier areas of the McKenzie Delta and offshore Atlantic. It also refers to prior Commission optimism over future Canadian gas exploration into the United States,[11] along with Staff's depreciation evidence in this proceeding, that being reliance in part upon increased Canadian exports.

Tennessee next refers to extra-record material allegedly not considered by the Commission[12] and concludes therefrom that Canada maintains its commitment to export gas.

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[11] *Consolidated Gas Supply Corporation,* Opinion No. 703, 52 FPC 454, 462 (1974); *National Gas Survey,* Volume I.

[12] *Canadian National Gas Supply and Requirements,* National Energy Board of Canada, April 1975, p. 94; *An Energy Strategy for Canada; Policies for Self-Reliance,* Minister of Energy, Mines

We deny Tennessee's application for rehearing of our exclusion in Opinion No. 769 of its Canadian advance payments. To begin with, as we pointed out in Opinion No. 769, Canadian advance payments are not sanctioned under our advance payment regulations. Accordingly, it is not enough for a pipeline to demonstrate compliance with such regulations. The sole basis for even considering Canadian advance payments is our prior statement that pending a Canadian advance payment rulemaking such advances "shall be treated on a case by case basis."[13] Our caution and restraint over Canadian advances is obviously due to the added uncertainty over ultimate resulting gas deliveries to the pipeline's customers arising from the need for export authorization. Consequently, a pipeline must demonstrate that receipt by the appropriate American consumers of the Canadian gas at issue will most likely occur. Tennessee did not make this showing.

In light of the heavy burden of proof imposed upon Tennessee, its evidence is inadequate. Tennessee founds its position of likely export authorization upon a 1971 NEB decision denying a request for authorization. Since in the Canadian advance payment context it is necessary to anticipate future export authorization, Tennessee's 1971 material is stale, especially in light of the significant changes in Canadian export policy, *infra,* since that time. Even when we consider this evidence on its own, it is unpersuasive: In 1971 the NEB found a 1.1 Tcf supply deficiency over the 25 times fourth year demand requirements. This finding entailed established Canadian reserves of 60.3 Tcf; therefore, Tennessee's assertion that estab-

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and Resources, 1976, pp. 67, 80, 81, and 124; and statement of the current Minister of Energy, Mines and Resources, Alastair Gillispie in December 1975.

[13] *Advances to Suppliers for Gas Outside Continental United States,* Docket No. R-466 Notice of Rulemaking, 38 Fed. Reg. 1055 (January 1973).

lished reserves need only exceed 34.2 Tcf is clearly erroneous. In addition Tennessee had introduced insufficient evidence to show that the NEB's 1971 exclusion of frontier reserves is likely to change. Its allegations of 30 Tcf from the Arctic Islands remains premature.

Turning to the beyond the record matter of which we are entitled to take administrative notice, the 1975 NEB report, *supra* note 12, is the most germane for the NEB is the Canadian agency charged with considering export authorizations. A reading of that report as a whole indicates that the NEB is now scrutinizing export applications much more closely in relation to Canada's energy needs and interests. In addition it is clear to the Commission that the NEB is no longer calculating the exportable surplus gas solely on the basis of reserves. It is also interested in deliverability: "The Board will henceforth make a case-by-case assessment of reserves and deliverability both when licenses, if any, are issued and at appropriate intervals." NEB report, *supra* note 12, p. 94. In this vein we note, by extrapolating from Tables 2 and 19 of the NEB report, that from 1975 through 1985 the NEB projects that the annual volumes available for export from the conventional producing areas will decline from 937 Bcf to zero. Furthermore, the NEB report indicates Arctic Island reserve estimates to range from 8.5 Tcf to 12.5 Tcf, not Tennessee's 30 Tcf. Finally, it is clear from the report that the NEB continues to exclude frontier area gas from its export deliberations due to uncertainty of amount and more importantly absence of any approved means of moving this gas to market.

The other official publication referred to by Tennessee, *An Energy Strategy for Canada, supra* note 12, does not support Tennessee's position. To begin with, as the authors recognized (p. 57) it is based on a " 'total energy' framework related to specific assumptions," while the NEB report is "derived from detailed analysis of the domestic oil

and gas markets on the basis of submissions received at public hearings and independent analysis." In that this publication was intended statement of general policy alternatives for the Canadian government, it is less germane to the issue at hand than is the NEB report. In addition the excerpts cited by Tennessee have been taken out of context, and their real import is not supportive of Tennessee's contention.

Tennessee appears to have misunderstood the real nature of the instant inquiry. It is neither our obligation nor intention to show that the NEB will refuse export authorization in the future. Instead, what we have demonstrated is that the likelihood of Tennessee's customers realizing increased deliveries from the reserves committed under this specific Canadian advance payment agreement is too small to justify imposing the resulting carrying costs upon the consumers served by Tennessee.

Finally, Tennessee's volunteered refund condition does not rectify the clear inadequacy of its case. Tennessee concedes that it would not seek export authorization until the mid-1980's. Accordingly, a final NEB decision is perhaps ten years away. This is too long a period before refunds might be required.

II. RATE DESIGN

(A) T-11 Transportation Rate

Trunkline applies for rehearing of the Commission's rejection of its proposed alteration of the T-11 rate under which it receives transportation service from Tennessee. It first seeks to clarify its proposed change in the T-11 rate. It requests in the alternative either that no storage costs being assigned to the T-11 rate (on the ground that the service is really an exchange and not transportation) or that storage costs be assigned on the Mcf/mile basis, which would mean less storage costs than under the present volumetric method. It only pursues, however, the latter request at this stage.

Trunkline contests the finding that the Commission in Opinion No. 352 [14] approved the allocation of storage costs on a system-wide or volumetric basis and asserts instead that the Mcf/mile method was adopted therein. It then attempts to justify Mcf/mile allocation of storage costs by citing excerpted evidence (Exh. 15) to show that the volumetric allocation approved in Opinion No. 769 assigns the largest portion of storage costs to the shortest haul, being its own T-11 service.

We find that rehearing should be denied as to Trunkline's proposed but rejected modification of the method of allocating storage costs to transportation service, in particular the T-11 rate under which it receives such service from Tennessee. As a preliminary matter Trunkline has incorrectly interpreted Opinion No. 352 to support allocation of storage costs to transportation service upon an Mcf/mile basis. When the Commission therein (27 FPC at 215) adopted the Administrative Law Judge's conclusion that "[t]he Tennessee method for allocation of costs to Transportation Service, utilizing the mileage from the actual points of receipt of transportation gas to the points of delivery, is reasonable," (27 FPC at 310) it in fact was approving the more detailed analysis in the body of the initial decision, (27 FPC at 280-281) which dealt specifically with "the allocation of transmission costs to transportation service." Accordingly, one cannot conclude from Opinion No. 352 that the Commission in fact adopted Mcf/mile allocation of storage costs to transportation service. All that can be said is that the issue had not been raised, most likely because of the relatively insignificant amount of storage costs versus transmission costs.

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[14] *Tennessee Gas Transmission Company*, Opinion No. 352, 27 FPC 202 (1962).

The Commission has subsequently adopted the policy of allocating storage costs on a system-wide volumetric basis, and this policy has received judicial approval.[15] The rationale underlying this policy is that the entire pipeline system gains economic and operational advantages from storage; therefore, storage costs should be allocated volumetrically, not according to distance. This policy is directly applicable to the Tennessee system because the availability of storage permits the operation of its upstream transmission facilities (from Texas to the storage fields) at 100% load factor, thereby reducing the needed investment in transmission facilities, as well as maximizing volumes and lowering unit transportation costs. (Exh. B-1, p. 5). We had previously found this to be true in the specific context of Tennessee when we issued Opinion No. 352 (27 FPC at 208, 243), and the controlling facts have not changed.

Trunkline's allegations of suffering a disproportionate burden resulting from volumetric allocation of storage costs as opposed to Mcf/mile based allocation are not supported by the record. To begin with, Trunkline's comparative allocation of storage costs excerpted from Exhibit 15 cannot be viewed in a vacuum. It must be remembered that Trunkline is allocated a substantial amount of storage costs relative to the other transportation service customers because its T-11 service constitutes around 60% of Tennessee's total jurisdictional transportation volumes. (Exh. 34). Secondly, its contention of a disproportionate 60% rate increase is also misleading because Trunkline's T-11 rate was not subject to Tennessee's last major rate increase filed in 1970.[16] This occurred because its T-11 rate was initially negotiated

[15] *United Gas Pipe Line Company*, Opinion No. 671, 50 FPC 1348, 1365 (1973), *aff'd sub nom, Consolidated Gas Supply Company, et al.* v. *FPC*, Nos. 74-1343 *et al.* (D.C. Cir. October 9, 1975), (Slip op. at 78).

[16] *Tennessee Gas Pipeline Company*, Opinion No. 619, 47 FPC 1327, 1346 (1972).

on the basis of Trunkline paying the transmission component of Tennessee's CD-1 rate for sales in its Southern Zone, thereby not affecting Tennessee's overall earnings. (Staff Item B by Reference).

Although it appears from its petition for rehearing that Trunkline has abandoned its original position that no storage costs at all should be allocated to transportation service allocated some storage costs but less than under system-wide allocation), we shall nonetheless restate our rejection thereof. As we found above, Tennessee's storage does benefit Trunkline's T-11 service. There is no basis for treating T-11 service as unique.

(B) Storage Injection Rate

Columbia and Consolidated, along with Brooklyn Union, contest our rejection of the proposed special storage rate, emphasizing the alleged benefits to the entire system from their storage investment. The real trust of their petitions is, however, to defer consideration of the special storage rate to the "top" case in order to be consistent with the deferral of the rate design issue.

We deny these petitions for rehearing. Our rejection of the proposed special storage rate in Opinion No. 769 is based on substantial evidence. Concerning the requested deferral these parties are not precluded from raising the issue again in the most recent Tennessee docket. We will not, however, defer the issue. In that Tennessee's rates were designed on the same 50/50 basis when these parties made their storage investments as was adopted in Opinion No. 769 for the locked-in effective period of this proceeding, these proponents of a special storage rate have not been prejudiced.

(C) SO-4 Rate

The two customers receiving deliveries under Tennessee's SO-4 rate, Columbia and Consolidated, apply for rehearing

of the Commission's change in the imputation of demand billing determinants for the SO-4 rate from using a 200% load factor to a 100% load factor. They assert that this change is not supported by the record for there is no evidence that SO-4 service is comparable to contract demand service. They argue that, instead, SO-4 service is inferior, for it is only delivered during the summer and required customer storage, as well as benefiting the entire system.

We also deny this basis for rehearing. We properly ordered that demand billing determinants for the SO-4 rate now be imputed on the basis of 100% load factor for the reasons stated in Opinion No. 769.

SO-4 service does differ from CD service in that under the former Tennessee has an obligation to deliver a fixed annual volume Tr. 1017) while under the latter Tennessee has an obligation to deliver a daily contractual volume; Tr. 1019) however, the record (Tr. 262) demonstrates that for purposes of the instant inquiry the two services are sufficiently similar to warrant use of the 100% load factor: there are no use restrictions upon SO-4 gas; SO-4 deliveries require transmission capacity to be provided by Tennessee; SO-4 and CD gas are of equal status in terms of Tennessee's curtailment plan; and Tennessee designed its transmission capacity to deliver SO-4 gas on an annual average day basis, which we note equates to contract demand service at 100% load factor.

(D) Berkshire's Allocation Method

Berkshire applies for rehearing of our rejection in Opinion No. 769 of its proposed modification of Tennessee's Mcf-mile allocation method. It begins by reiterating the alleged factual predicate for its Mcf-mile adjustment, that being the finding in the initial decision underlying Opinion No. 352 that the unadjusted Mcf-mile zonal allocation over-

charges customers in the New York and New England zones, (27 FPC at 243-244) and the record evidence of a current annual overcharge to the New England zone of $3,000,000. Berkshire proceeds to contest our finding that its method constitutes zone-gate allocation, which has admittedly been rejected by the Commission. It contends that there is no record support for this finding upon which the Commission solely relied.

Berkshire continues by attempting to explain its proposed adjustment. It premises this adjustment upon the two sources of Tennessee's system supply 1300 miles apart, the Texas-Louisiana gas fields and the Pennsylvania-New York storage fields, and it then contends that these two supply sources affect transmission capacity investment in that the flow gas from the producing fields supply average day requirements while storage supplies peak requirements. Berkshire contends that Tennessee's Mcf-mile method ignores these factors while it would also apply an adjusted Mcf-mile method to systemwide transmission costs. It would also change the allocation of storage costs. Berkshire concludes by arguing that, since it would continue to use Tennessee's overall rolled-in transmission costs, it has not advocated a zone-gate method of allocation.

We find that Berkshire's application for rehearing should be denied. Because of the complexity of this issue, however, we shall elaborate upon our discussion in Opinion No. 769.

We have again reviewed Berkshire's presentation (Exh. B-1, 58, 59, 60) and conclude that its proposed allocation adjustments are improper. In order to fully understand our reason for so concluding, it is first necessary to keep in mind the difference between Mcf-mile and zone-gate allocation. Under the Mcf-mile method the volumes delivered at each point within a particular zone are multiplied by the number of miles from source of supply to such point of delivery to derive a total number of Mcf-miles for each zone. Then a ratio is established between each zone's

aggregate Mcf-miles and the total Mcf-miles for Tennessee's system as a whole, and this ratio is then used to allocate Tennessee's rolled-in system-wide transmission costs among the zone. By contrast under the zone-gate method the transmission costs associated with the facilities physically located within each zone are assigned to that zone as if it were a separate operating entity which purchases gas from the next upstream zone and sells it to its own customers and to the next downstream zone. The transmission costs assigned to a particular zone and the cost of gas from the contiguous upstream zone are allocated to all volumes sold in that zone or delivered to the next downstream zone on a uniform average basis.

The Commission in Opinion No. 352 adopted the Mcf-mile method upon findings "that Tennessee operates a fully integrated transmission system, that it provides essentially the same type of pipeline service in all of its zones, and that the zone boundaries do not correspond to any actual divisions in system operations or services." Neither has Berkshire contested the continued validity of this determination nor have conditions so changed on the Tennessee system to negate our prior adoption of the Mcf-mile allocation of transmission costs by which we intended to recognize the importance of the distance of transmission.

The origin of Berkshire's present position is the Commission's query in Opinion No. 352 whether the difference in load factor and load density between the New England zone and Tennessee's five other zones necessitates a special adjustment of the Mcf-mile method for the New England zone. (27 FPC at 210-211). Berkshire now contends that the Commission in Opinion No. 769 ignored the concern expressed in the initial decision underlying Opinion No. 352 that the New England zone is being overcharged under Mcf-mile allocation. Unfortunately, Berkshire has misread both the initial decision and Opinion No. 352. The Administrative Law Judge found potential for overcharging the

New England zone under zone-gate allocation. On the other hand he found that Mcf-mile allocation would minimize this potential because the use of system average costs would balance out individual advantages and disadvantages. (27 FPC at 244). In addition the Commission further found that such service characteristics as load density and load factor did not differ so much between the New England zone and Tennessee's other zones as to require a special adjustment for New England, (27 FPC at 211-212) and the Commission's cost allocation 50% on Mcf-mile and 50% on historical revenue pattern (27 FPC at 213) related not to the New England issue but instead to the Commission's desire for a gradual and orderly transition to Mcf-mile allocation. Accordingly, Berkshire must advance independent justification of its Mcf-mile adjustment not relying upon Opinion No. 352.

As we have already shown in our discussion above of Trunkline's proposal, *supra* p. 15, it is proper for Tennessee to allocate storage costs upon a system-wide basis because all customers benefit from storage, whether upstream or downstream. Berkshire's method would require termination of that method of allocating storage costs because it would instead allocate storage costs upon actual use. (Exh. B-1, pp. 3, 9-12). Berkshire's definition of actual use being the difference between annual average day and peak day deliveries leads to storage costs being allocated to a select group of Tennessee's customers. We have already found substantial evidence to support system-wide allocation of storage costs. The real crux of Berkshire's position is the undisputed fact that Tennessee's system is designed on an average annual day basis (100% load factor) from supply to storage (upstream) and on a peak day basis from storage to those customers downstream from storage.[17] Such design

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[17] In light of this design fact Berkshire would allocate transmission and storage costs as follows: Upstream zones would multi-

and operational realities of the Tennessee system do not, however, warrant abandonment of the equitable and appropriate method of allocating storage costs on a systemwide basis.

Notwithstanding Berkshire's protestation to the contrary, its proposal leads inexorably to zone-gate allocation. Although it is true that Berkshire's proposal, on its face, does not exactly resemble the definition of zone-gate allocation provided above, it is not enough to accept Berkshire's Mcf-mile adjustment at face value. Examination of Berkshire's Mcf-mile adjustment for allocating transmission costs shows that it has segregated Tennessee's transmission system into the two parts of upstream and downstream of storage to compute its transmission allocation factors; however, it applies these allocation factors to the rolled-in system-wide transmission costs instead of to the costs of each of the segregated parts. The inconsistency of this method becomes apparent by comparing the end-results obtained by Berkshire. Based on its Exhibit No. 60, Berkshire's method results in a weighted average unit cost per Mcf per 100 miles allocated to the New England Zone of 2.05 cents, Central Zone of 2.12 cents and, Southern Zone of 2.27 cents (Tr. 690-691), even though the New England Zone's load factor is lower than either the Central or Southern Zones (Tr. 685-686). The New England Zone's lower unit cost and lower load factor flow from this inconsistency because under the proper matching of allocation factor and costs, load factor is inversely proportionate to unit cost, unlike the present direct relation found in Berkshire's method.

When we remove this inconsistency in Berkshire's adjustment and accordingly segregate the system for pur-

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ply average day takes of each customer therein by the transportation distance. Downstream zones would multiply average day takes by the distance from supply to storage and add that to the product of multiplying peak day takes by the distance from storage to delivery.

poses of both computing allocation factors and cost, the impact of this Mcf-mile adjustment approximates the impact of using zone-gate allocation. Berkshire has neither adequately demonstrated that the New England zone is being unfairly treated under the present allocation method nor justified divergence from the well-established treatment of Tennessee as an integrated system using rolled-in system-wide transmission costs.

III. DEPRECIATION

Only Tennessee seeks rehearing of the Commission's increase of its book depreciation rate from 3.6% to 4%. Tennessee had originally proposed an increase to 5.75% and maintains that position on rehearing. Tennessee makes a number of arguments, many of which the Commission has already considered and rejected in Opinion No. 769. It first attacks Commission adoption of Staff's 4% composite depreciation rate. It views Staff's presentation as deficient for two reasons. To begin with, Tennessee alleges that Staff failed to include annual interim retirement losses in its composite rate, and it contends that an allowance of .5% for interim retirements is shown on the record. Tennessee views Staff's addition of this undisputed .5% interim retirement rate to the reserve for depreciation for interim retirements as inadequate for such treatment unreasonably defers recoupment of such costs to future ratepayers. Tennessee also asserts that Staff had added an increment to the composite depreciation rate for interim retirements in many other pipeline rate proceedings, that the Commission has previously recognized such treatment of interim retirements, and that this would increase Staff's composite rate to 4.5%.

Tennessee moreover attacks Staff's 4% rate on the ground that Staff's own average remaining life study clearly demonstrates need for a 5.15% composite depreciation rate. Specifically, Tennessee contends that Staff failed

to use the remaining lives from one study in its computation of the 4% composite rate, and moreover admittedly employed the wrong schedule of major retirements, the correction of these two mistakes allegedly resulting in a 5.15% composite depreciation rate. Concerning the first of two alleged Staff mistakes, Tennessee seeks to refute Staff's justification for not using its average remaining lives study, which is that such study reflects future plant additions which should not be charged to current customers.

Tennessee then asserts that the Commission failed to comply with Section 9 of the Natural Gas Act for, by noting the possible inadequacy of Staff's 4% rate, the Commission did not find that the rate set is "proper and adequate" as per Section 9. Tennessee in essence argues that the Commission could not set a depreciation rate which it found might not be adequate. It refers specifically to the Commission's expressed doubt as to the supplemental supplies relied upon by Staff, and it concludes that by leaving the rate at 4% the Commission acted inconsistently with Opinion No. 734.[18]

Tennesse proceeds to attack the Commission's rejection of the unit of production method for all other plant than gathering, specifically asserting conflict with Opinion No. 762.[19] Tennessee then recites its evidentiary presentation supporting the unit of production method. Finally, Tennessee contends that the evidentiary presentation underlying its unit of production approach and 5.75% composite depreciation rate comport with the *Memphis* case,[20] upon which the Commission relied in Opinion No. 769.

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[18] *Columbia Gulf Transmission Company,* Opinion No. 734, Docket Nos. RP73-85 and RP73-86, issued June 12, 1975. (Slip Op. at 24).

[19] *Natural Gas Pipe Line Company of America,* Opinion No. 762, Docket No. RP74-96, issued May 21, 1976 (Slip. Op. at 28-29).

[20] *Memphis Light, Gas and Water Division* v. *FPC,* 504 F.2d 225 (D.C. Cir. 1974).

We find that rehearing should be denied as to the depreciation rate issue, and accordingly, Tennessee's composite depreciation rate should remain for this proceeding at 4%. Based upon the record before us only the Staff's depreciation presentation leads to a proper and adequate result. Although we found in Opinion No. 769, slip Op. at 7, that due to post-record events regarding the likelihood of increased supplemental supplies the 4% depreciation rate "could well be inadequate", from the perspective of this record 4% is adequate. We feel justified in limiting our analysis to record evidence because the instant proceeding is "locked-in" and Tennessee's future proper and adequate depreciation rate is presently being litigated in several subsequent proceedings, including RP75-13 and RP75-113. Tennessee's incantation of the Section 9 "proper and adequate" depreciation rate provision is misplaced. Presently before the Commission is a Section 4 rate change proceeding in which Tennessee has not met its burden of proving that the 5.75% composite rate sought is just and reasonable. Staff's study provides substantial evidence to increase Tennessee's rate from 3.6% to 4%. Even if the Commission were to act *sua sponte* pursuant to Section 9, any conceivable depreciation rate increase would affect rates prospectively only. We feel confident that Section 9 will be satisfied by the current adjudication in Tennessee's three subsequent rate change proceeding. Traditional and supplemental gas supply evidence of more current quality is available therein. A determination of "proper and adequate" depreciation rates in the context of a rate change proceeding, as contrasted to a pure accounting matter, is circumscribed by the procedures of Section 4 of the Natural Gas Act.

Before addressing Tennessee's numerous arguments, we point out that we do not have a burden of proof *vis-a-vis* each and every aspect of Staff's depreciation case, as Tennessee would suggest. Instead we have reviewed the record as a whole and find that Staff's 4% composite depreciation

rate reaches the correct result for the effective period of the rates in question.

We reject Tennessee's first contention that Staff's 4% composite rate should at a minimum be increased to 4.5% to account for .5% annual interim retirements, which Staff allegedly ignored. Interim or normal retirements are all retirements from plant which occur in the course of normal operations due to normal forces, being either physical causes like wear and tear or functional causes like obsolescence, inadequacy or requirements of public authorities. We have consistently found that interim retirements should be reflected in the depreciation rate, and the record herein indicates that an interim retirements rate of .5% is reasonable (Exh. S-6, p. 7). Tennessee expresses concern for it could not find the inclusion of this .5% interim retirement rate in the 4% composite depreciation rate. As we shall explain, while Staff's depreciation study (Exh. 46) did not specifically identify the interim retirements, the ultimate result reached by Staff is equivalent to the result that would have been reached if it had identified the interim retirements by name. In order to demonstrate this fact we shall focus upon the major component of Tennessee's plant, the main transmission line to compressor station #219.

Although Staff did not separate out interim retirements, we find that the methodology employed by Staff, which resulted in a more rapid write-off of plant than would normally occur, necessarily encompasses interim retirements. To begin with, it is clear from Exhibit 46, Schedule No. 5 that, in determining a major retirement pattern for the mainline to station #219 at 5% per year, Staff was directly relating retirements to declining average day deliveries or throughout on approximately a one to one ratio. (Exh. S-9, pp. 26-27). Staff was very conservative in this approach which results in a more rapid rate of depreciation than would normally be allowed. We know that this 5% rate of major retirements is accelerated because

retirements and deliverability do not correspond on a one-to-one basis. Plant is retired less rapidly than deliverability declines because a pipeline company will in general first retire compression which is proportionately less expensive than pipe. Accordingly, by keying major retirements to declining average day throughput Staff in effect included an increment for interim retirements.

A second aspect of Staff's study accentuates our certainty that interim requirements have been adequately represented in the 4% depreciation rate. Exhibit 46, Schedule No. 5 indicates that in calculating the 16 year average remaining life for Tennessee's main line to Station #219 Staff took the extremely conservative stance of using only a 10% minimum back-bone system. The effect of this Staff approach is to increase the depreciation rate. If Staff had employed a greater back-bone system, the result would have been more dollar years, which when divided by total retirements would yield an average remaining life of more than the 16 years found by Staff, which in turn when employed in Column 6 of Exhibit 46, Schedule No. 6, Sheet 2 to be divided into depreciable base (Column 5) would result in less annual depreciation expense (Column 7) and thereby lead to a lower depreciation rate (Column 10). Staff would have been justified in employing a greater minimum back-bone system, but in choosing 10% we feel that interim retirements are necessarily compensated in the 4.18% employed by Staff for the mainline to Station #219. (Exh. 46, Schedule No. 1).

Our conclusion that interim retirements were adequately considered is further buttressed by Appendix B to Staff's brief opposing exceptions filed in this proceeding on June 3, 1975. We note from Columns 5 and 6 therein that Staff broke down retirements into normal (interim) and major, and yet the depreciation rate for the three year period from 1972-1974 for the mainline to Station #219 was only 4.04%, which is below the 4.18% employed by Staff in

reaching the composite rate of 4%. While this is not evidence per se, it confirms what we have already learned from the record.

We also reject Tennessee's contention that Staff's studies demonstrate that the composite rate should be 5.15%. Tennessee relies in this regard upon Exhibits 46, Schedule 6, Sheets 1, 2 and 3 in which Staff ran through some computations concerning the three segments of Tennessee's transmission system but did not treat the average remaining lives in the same fashion as it did elsewhere. It also relies upon a Staff statement made on brief that Staff employed the wrong schedule of major retirements. The essence of its argument is that, while Staff calculated *average* remaining lives, its depreciation rates of 2.46%, 4.18%, and 3.27% for the distribution loop, mainline to Station #219, and Texas mainline respectively were erroneously the *current* rates, not the average rates of 3.10%, 4.98%, and 4.32% respectively. It views this failure to employ the average rate unfair to future ratepayers.

Tennessee, however, misconstrues Exhibit 46, Schedule 6, Sheets 1, 2, and 3. It is clear to us that these sheets were employed by Staff to calculate the current depreciation rates, which it did by averaging the initial three year period of 1973 through 1975. This was a shorthand calculation since Staff correctly felt that only the current, not average, rate was important. The average rates for these three transmission segments shown in these sheets are patently inaccurate because Staff for purposes of convenience did not relate the average remaining lives to the 28 year economic life which is central to Staff's study. (Exh. 46, Schedule Nos. 4 and 5). Again referring to Appendix B of Staff's brief opposing exceptions, our conclusion above is borne out as we notice that for the mainline to Station #219 segment the average rate is 4.21%, not the 4.98% shown in Exhibit 46, Schedule No. 6, Sheet 2. The reason for this substantial difference is that in Appendix B Staff continued its

study for the full 28 year economic life, that is to the year 2000. We note that this average rate of 4.21% is so close to Staff's current rate of 4.18% for this segment (Exh. 46, Schedule 1) that Tennessee's contention that Staff erred in not using an average instead of current rate is for all intents and purposes moot under the facts of this case. Moreover, we feel that the question of average versus current depreciation rate is more appropriately addressed in Tennessee's more recent filings, of which there have been three. The question of equity between present and future ratepayers is not framed well in the present context of determining refunds for a locked-in 15 month period.

Tennessee also misconstrues Staff's statement on brief about retirement schedules. Although Staff conceded that it should have employed the same retirements schedule in computing the depreciation rate for the mainline to station #219 as it used in computing the average remaining life, it accurately concluded that the 4.18% depreciation rate for the mainline to Station #219 is nonetheless correct because the retirement schedule it employed for calculating the 16 year average remaining life included no such retirements until 1978 while the 4.18% is the 1973-1975 average. (Exh. 46, Schedule No. 5).

We have already concluded that Section 9 of the Natural Gas Act has not been contravened by our establishment in Opinion No. 769 of a composite depreciation rate of 4%. In addition we do not see this result as inconsistent with Opinion No. 734, *supra* note 18, which is clearly distinguishable: 1.) Although the Commission therein adopted a rate of 3.75% for Columbia Gas' transmission and underground storage facilities and accordingly declined to use Staff's 3.65% rate, the controversy was merely one of *degree* of gas supply decline since Staff, the pipeline, and the Commission had all concluded that the record supported use of the unit of production method. In the instant case, however, Staff's evidence as to supplemental supplies and gas re-

serves was introduced to refute applicability of the unit of production method in the first instance. 2.) Opinion No. 734 arose from a settlement while the instant proceeding entails a fully litigated record. 3.) The difference between Staff's 3.65% proposed rate and the 3.75% rate found in the settlement are minimal compared to the disparity between Staff's 4% rate and Tennessee's 5.75% proposal. In Opinion No. 762 [21] the Commission stated that the conclusion in Opinion No. 734 (the evidence on non-traditional sources of supply was too speculative for use in setting Columbia's depreciation rate) "was not intended to mean that evidence on non-traditional gas supply sources was not relevant; rather, it described the limitations of the existing record upon which the Commission was forced to rely."

Tennessee's reliance upon Opinion No. 762, *supra* note 21, is likewise misplaced. Tennessee alone presented a unit of production study herein, and it is clearly deficient under the court mandate in *Memphis, supra* note 20. On the other hand in Opinion No. 762 the Commission had a better unit of production study prepared by the pipeline, along with a unit of production study prepared by Staff and also two straight-line depreciation studies, which tend to support the settlement depreciation rate. Finally, our rejection of Ni-Gas' position in Opinion No. 762 is based upon the conclusion that it is unreasonable and unnecessary to "hypothesize a figure representing *all possible* future volumes to pass through [the pipeline's] system during the remainder of its physical or economic life. . . ." This is significantly different from the instant proceeding in which Tennessee failed to give adequate consideration to supplemental supplies in general.

Finally, we remain convinced that Tennessee's unit of production presentation does not comport with the court's

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[21] *Natural Gas Pipe Line Company of America,* Opinion No. 762, Docket No. RP74-96, issued May 21, 1976, (Slip Op. at 28).

mandate in *Memphis, supra* note 20. Our discussion on this point in Opinion No. 769 is correct, and we rely thereupon. We have already considered Tennessee's depreciation evidence cited in its application for rehearing and have found it legally deficient. It is not enough for Tennessee at this stage to cite conclusory statements by its witness that it assumed future supply additions and to note that in subsequent Tennessee rate change proceedings Staff has also presented a unit of production study: Our decision herein is not against the validity of the unit of production concept per se but is instead against the quality of Tennessee's evidentiary presentation in this specific case. In its application for rehearing Tennessee seems to forget that it has the burden of proof under Section 4 of the Natural Gas Act, as well as forgetting the legal distinction between some evidence and substantial evidence.

IV. RATE OF RETURN

PSCNY alone seeks rehearing of the rate of return prescribed in Opinion No. 769. It first expresses doubt that a valid Commission decision was rendered as to rate of return in that only Chairman Dunham and Commissioner Watt supported the 13.75% return on common equity prescribed therein, Commissioner Holloman dissenting to both rate of return and front-end advance payments and Commissioner Smith concurring in Opinion No. 769 but opposing the 13.75% return on equity. PSCNY also opposes the specific 13.75% return on equity allowed in Opintion No. 769, although it restricts its argument to the unreasonableness of this rate of return in the instant "locked-in" context. It primarily relies upon the fact that in Opinion No. 762, *supra* note 21, the Commission allowed Natural Gas Pipeline a 13.5% return on equity for a locked-in period ending eight months after the effective period of Tennessee's rates in this proceeding. PSCNY sees this 13.5% rate of return on equity as the ceiling for

Tennessee. It also attacks the lack of financial and operational comparison in Opinion No. 769 between Tennessee and other pipelines of similar risk.

We find that PSCNY's application for rehearing of the rate of return allowance should be denied, and therefore we retain the 9.25% overall rate of return and 13.75% return on common equity prescribed in Opinion No. 769. To begin with, Opinion No. 769 is a legally sufficient Commission decision. A majority voted in favor of the overall result reached. Commissioners Smith and Holloman's opposition to the rate of return allowance does not vitiate this majority vote, as Commissioner Smith recognized in his concurring opinion.

As to PSCNY's substantive attack on the 13.75% return on common equity, this rate of return was properly within the zone of reasonableness between 12.5% and 14%. Sufficient differences exist between the operations and finances of Tennessee and Natural Gas Pipeline to warrant the 0.25% gap between their respective returns on common equity allowed in Opinion Nos. 769 and 762.

The Commission further finds:

The assignments of error and grounds for rehearing set forth in the applications for rehearing of Opinion No. 769 by Tennessee, Berkshire, Trunkline, INGAA, Transco, Columbia and Consolidated, Brooklyn, and PSCNY present no facts or legal principles that would warrant any change in or modification of the Commission's Opinion No. 769.

The Commission orders:

The applications for rehearing filed by Tennessee, Berkshire, Trunkline, INGAA, Transco, Columbia and Consolidated, Brooklyn, and PSCNY are hereby denied.

By the Commission.

Commissioner Smith, concurring, filed a separate statement appended hereto.

Commissioner Holloman, dissenting, filed a separate statement appended hereto.

(SEAL)

Kenneth F. Plumb,
Secretary.

TENNESSEE GAS PIPELINE COMPANY
(a Division of Tenneco, Inc.)

(Issued May 31, 1977)

SMITH, Commissioner, *concurring:*

Federal regulation of the interstate pipeline system naturally creates for pipelines expenses which are not always recoverable. When, because of overriding public interest considerations, the pipeline rather than its customers must absorb these expenses, the Commission has the obligation and the responsibility to take this fact into account in the establishment of just and reasonable rates.

In the facts at hand, the majority has correctly excluded from rate base a very large amount of front-end advance payments made by Tennessee.[1] This exclusion, however, necessitates affording Tennessee a higher rate of return than otherwise would be justified on the record before us. For this reason, I concur in the majority order.

/s/ DON S. SMITH
Don S. Smith,
Commissioner

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[1] These advances had not been expended by the recipient producers prior to the effective date of the proposed rates and Tennessee failed to demonstrate on the record that any positive benefits to the consumers would result if the advances were included in rate base. *See, e.g.*, Opinion No. 801, Transcontinental Gas Pipe Line Corporation, Docket Nos. RP74-48 and RP75-3, issued May 31, 1977.

TENNESSEE GAS PIPELINE COMPANY

(a Division of Tenneco, Inc.)

(Issued May 31, 1977)

HOLLOMAN, Commissioner, *dissenting:*

Upon rehearing the majority attempts to reinforce an indefensible position by expanding its rationale for excluding front-end advance payments from Tennessee's rate base while overcompensating for this harsh result with an excessive rate of return. Rather than extracting itself from this self-inflicted dilemma with a simple admission of past error on both counts, the majority stubbornly clings to the idea that two wrongs can make a right; that a sort of rough-handed justice can be attained by offering one error as a *quid pro quo* for another. In so doing, the majority's effort is doomed from the start.

First, having thoroughly and carefully reviewed the briefs of the parties, the pertinent parts of the record referred to, the Initial Decision and Opinion No. 769, nothing contained in Opinion No. 769-A dissuades me from my earlier conclusion that Tennessee has presented substantial and unrebutted evidence, as well as a compelling legal case, that its advances were "reasonable and appropriate" and well within the letter and spirit of Order No. 465.

While the Commission has terminated the advance payment program prospectively, I believe we have an obligation to phase out these arrangements in a fair, equitable and legal manner. In making these determinations, it is not enough to recognize that these arrangements were entered into by the pipelines at the express invitation of the Commission. For the plain fact is this program was thrust upon the pipeline companies, leaving them little choice but to negotiate for these arrangements or abandon the field to competing pipelines. Obviously, considered in the context of growing curtailments and deteriorating gas supply,

the latter course would have evidenced a willful disregard of Tennessee's responsibilities to its customers bordering on negligence. When viewed in the context of the times; the Commission's often stated intent that the advance payment program was a novel and experimental one designed to give the participants a free reign and the widest latitude in fashioning workable arrangements; the actual and constructive notice to the Commission of the massive and ongoing nature of these front-end contracts; the common knowledge within the industry that these unlimited front-end advances were "the name of the game;" and in light of the record evidence in this case, these advance payments are clearly within the "reasonable and appropriate" standard of Order No. 465 and should be included in rate base. Clearly, this Commission cannot give retroactive application to its current notions as to what a past Commission should have said or done.

On April 28, 1975, the Commission instituted an extensive investigation of the entire advance payment program, from its inception in response to the mandate in *Public Service Commission of the State of New York* v. *F.P.C.*, 511 F.2d 338 (CADC, 1975), wherein the Court remanded the record relating to Orders No. 465 and 499. All pipelines making and producers receiving advance payments under the program were made respondents to that proceeding. A review of the proceedings involved in Docket Nos. R-411 and RM74-4, as well as the Commission's termination order of December 31, 1975, reveal a thorough investigation of the advance payment program. The Commission's order itself reveals that the pending contracts and the provisions thereof were thoroughly reviewed in connection with our decision to terminate prospectively and continue the executory provisions of existing agreements. For example, the Commission said on page 19: "we note that some advance payments contracts permit the addition of new prospects or tracks from time to time." On page 15 the Commission noted that all of "the Alaskan

advance payments contracts which are subject to Order 499 contain 'escape clauses'." Thus, after reviewing the contracts in effect on December 31, 1975, the Commission set forth the terms and conditions under which the program would be terminated and the executory portions of existing contracts phased out.

The Commission was well aware that the executory provisions of those contracts entered into under Order No. 465 provided for unlimited front-end advances. The Commission did not order, even prospectively, the termination of future advances made under the executory portions of those contracts. Furthermore, the Commission specifically declined to order refunds because, as stated on page 17:

> "Moreover, ordering the pipelines to make refunds would impose a tremendous financial hardship on the pipelines because there is no guarantee whatsoever that the pipelines would be reimbursed by the producers for the carrying charges the pipelines would have to refund to their customers."

Yet, for all practical purposes that would be the result of the Commission's decision in this case. For example, the record evidence here (Exhibit 82-8) shows that the advance payments excluded here equal approximately 10 percent of Tennessee's rate base. Unfortunately, this is only the tip of the iceberg. According to pleadings filed by INGAA, its members "have made or committed to make substantially more than $1 billion in Order No. 465 advances, and more than $5 billion in advances pursuant to the Commission's advance payment program." Furthermore, according to the sworn statements filed by INGAA, less than 1 percent of these advances were made or committed on a 30-day installment basis. When viewed in light of these facts, the enormity of the Commission's error in this case becomes apparent, especially in view of the foregoing statement by this Commission in its order terminating the

advance payment program. The devastating results which must necessarily follow an extension of the Commission's decision today, that is the exclusion of 99 percent of the $5 billion in outstanding advances, will not only fall on the interstate pipelines involved but upon their distributors and end-use customers as well. That is precisely the reason for the concern expressed by the Public Service Commission of the State of New York and other customers of Tennessee in this proceeding. The statements by New York and other customers would appear at first blush to be declarations against interest. Upon further analyses, however, it is clear that they support the inclusion of these advance payments precisely for the reason that it is in their best interest. For example, at page 1 of its Initial Brief, East Tennessee Natural Gas Company states: "Without the assurance of favorable rate base treatment of advance payments by the Commission, East Tennessee is fearful of disastrous affects upon long-term reserves dedicated for interstate sales which are vitally important in today's gas supply situation."

Of course it is true that some producers may be willing to abrogate existing advance payment agreements on the basis of today's decision. The extent to which producers will be willing to cancel these agreements, and withdraw their commitments to dedicate intrastate supplies to the interstate system is uncertain.

In view of all of the foregoing circumstances Commissioner Smith's characterization of today's decision as "traumatic" must be considered a considerable understatement. It could more accurately be characterized as "disastrous" or "devastating" or "ruinous'' Having wandered into this legal thicket the majority will be hard put to find a way out in future cases.

In addition to the 30 day rule some recognition should be given to the majority's strange notions as to the burden of proof standard to be applied to Tennessee's case. Dis-

regarding the overwhelming evidentiary case made by Tennessee in support of these advance payments the majority invents an evidentiary standard more ingenious than the 30 day rule itself. In essence, the majority contends that the mere mention of the so-called 30 day rule in Staff's testimony shifted the burden of proof on this issue to Tennessee. In essence, the Staff has contributed but one salient observation on this point: that payment by Tennessee to the producers "were made considerably in advance of the estimated time . . . at which each producer would require such amounts to cover his cumulative exploration, development and production cost". (Exhibit S-10, Testimony of Commission Staff witness Robert H. Benna, at 4; Exhibit 49.) Furthermore, Staff offered no rationale whatsoever for its 30 day rule, as demonstrated by the following colloquy:

> Q. What do you consider to be a reasonable time period between payment of advances by Tennessee and utilization of those advances by the producer?
>
> A. There has been no justification submitted for advancing funds more than 30 days prior to the time such funds are required by the producer to cover his costs. EX. S-10, *supra.* at 5.
>
> Q. On what basis have you determined that Order No. 465 requires that advances be reasonably related to costs in order to be considered "reasonable and appropriate"?
>
> A. In the Order Denying Rehearing of Order No. 499 issued February 22, 1974, the Commission stated (mimeo, p. 3): ". . . we have full authority to examine advances made prior to December 28, 1973, for reasonable relation to costs under the "reasonable and appropriate" standard of our previous advance payment orders." Thus, while the cost-relationship requirement is not spelled-out in Order No. 465, the

requirement is inherent in the order's "reasonable and appropriate" requirement for rate base treatment. Id. at 5.

Yet based on nothing more than a few lines in this record from Staff witness Benna, the majority finds that Tennessee has assumed not only a responsibility but a heavy burden of proof to rebutt. As asserted by the majority:

> "Since the burden of proof was upon Tennessee to rebut the thirty day rule and it ignored the burden, the Commission need not support the thirty day rule by substantial evidence for it has not made an affirmative finding as to the specific thirty day threshold."

As a *non sequitur*, this statement is without parallel. If it has left me stunned as a principle of law or logic, it will surely bring an audible gasp for some reviewing Circuit Judge. While this novel evidentiary theory, heretofore unknown in the development of administrative law, is at least commendable for its sheer audacity, it cannot be relied upon by reasonable men. To the contrary, Tennessee was under no obligation whatsoever to assure a burden of proof or even a responsibility to answer every half-baked notion thrown out by Staff's witness.

I next turn my attention to the majority's statement that "it is clear that the Commission has not taken a *per se* view of these front-end advances." The majority further states "we reject the contention that the Commission has ignored its prior pronouncements of avoid a *per se* stance and adopting a case-by-case approach." In Opinion No. 769 the majority found that these payments are "presumptively extravagant," and then made it clear, that for all practical purposes, it considered this to be an irrebuttable presumption. As stated by the majority:

> "Nor do we think Tennessee could make such a showing." (Opinion No. 769, p. 31.)

In view of the foregoing it can be fairly stated that the majority has elected to treat these advance payments as a *per se* violation of the reasonable and appropriate standard of Order No. 465.

Tennessee has presented an overwhelming case demonstrating that the Commission had actual and constructive notice that the pipelines and the producers responded to this program with agreements calling for unlimited front-end advances from its inception and throughout the period covered by Order No. 465. Yet the majority dismisses Tennessee's allegation of Commission knowledge of the existence of substantial front-end advances as "not only unfounded but also inappropriate." On this point the majority's contention is simply devastated by the "Application of Tennessee Gas Pipeline for Rehearing and Reconsideration of Opinion No. 769." I will therefore resist the temptation of enumerating, beginning with the inception of the advance payment program, the long list of Commission proceedings, orders, opinions and pronouncements evidencing its awareness that front-end advance payments were the "name of the game" beginning with Order No. 410 and throughout the period covered by Order No. 465. Nor will I list or cite from the Initial Decisions of our Administrative Law Judges, unanimously upholding front-end advance payments under Order No. 465, or the many court decisions on this subject. These are extensively treated in the Applications for Rehearing filed by various parties in this proceeding. However, as to the majority's contention that its so-called 30 day rule is "implicit" in Order No. 465 as well as in those orders preceding it, I note the recent decision by the D.C. Circuit Court of Appeals in the case of *United Gas Pipe Line Company* v. *F.P.C.*, D.C. Circuit Nos. 75-1943 and 75-2051, issued February 24, 1977, wherein it states:

> "Secondly, and perhaps more importantly, we have found nothing in the Commission's orders setting up

the advance payment program to indicate that the producers who were given such payments had to demonstrate an actual need *for* them.. It is apparent that the Commission instituted the advance payment program merely as a means to enhance significantly the supply of natural gas in the interstate system during a period of critical nationwide gas shortages. It declared that the program was expected to intensify the development of new sources of natural gas supplies and thus alleviate the supply shortage, but it never expressly mandated that a producer show that *but for* the advance payments it would not be able to obtain the necessary exploration and development capital." [Footnote omitted.]

The D.C. Circuit Court refused to uphold the Commission's summary rejection of United's rate filing, stating further:

> ". . . The Commission, of course, should view the Agreements in the context of the time which produced them—a time of severe natural gas shortage when experimental programs fashioned to alleviate this problem were being implemented."

In conclusion the majority opinion in this case represents a classic example of retroactive ratemaking. This Commission, having adopted Order No. 465 in a rulemaking proceeding cannot adopt a different standard today and apply it retroactively. Neither can the majority change the record or amend established evidentiary rules to support its *post hoc* rationalizations. Furthermore, the majority's attempt to do so violates every concept of due process and reasoned decision making. These payments by Tennessee are well within the plainly stated letter, spirit and intent of Order No. 465. Once a regulatory agency adopts a standard of general applicability in the exercise of its rulemaking authority it cannot subsequently

apply another rule in its quasi-judicial capacity. As stated by the Supreme Court in the case of *Arizona Grocery v. Atchison Railway,* 284 U.S. 370, 389 (1923):

> As respects its future conduct the carrier is entitled to rely upon the declaration as to what will be a lawful, that is a reasonable, rate; and if the order merely sets limits it is entitled to protection if it fixes a rate which falls within them. Where, as in this case, the Commission has made an order having a dual aspect, it may not in a subsequent proceeding, acting in its quasi-judicial capacity, ignore its own pronouncement promulgated in its quasi-legislative capacity and retroactively repeal its own enactment as to the reasonableness of the rate it has prescribed.

Therefore, to the extent the majority opinion excludes advance payments made pursuant to Order No. 465, I dissent.

Lastly, I would affirm and adopt the rate of return determination and supporting rationale set out in Judge Kanell's Initial Decision. By apparently attempting to make Tennessee whole through an award of an unreasonably high rate of return the majority has only compounded its error.

/s/ JOHN H. HOLLOMAN III
John H. Holloman III
Commissioner

APPENDIX D

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

September Term, 1979

No. 77-1496

TENNESSEE GAS PIPELINE COMPANY
a division of Tenneco, Inc.,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

PUBLIC SERVICE COMMISSION OF THE STATE OF NY, et al.,
Intervenors

No. 77-1712

TRANSCONTINENTAL GAS PIPE LINE CORPORATION,
Petitioner

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

COLUMBIA GAS TRANSMISSION CORP., et al.,
Intervenors

AND CONSOLIDATED CASES

Filed October 31, 1979

BEFORE: Leventhal and Wilkey, Circuit Judges; and Greene*, Judge, United States District Court for the District of Columbia

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* Sitting by designation pursuant to Title 28 U.S.C. § 292(a).

ORDER

Upon consideration of the petitions for rehearing filed by petitioners Tennessee Gas Pipeline Company and Transcontinental Gas Pipe Line Corp., response of respondent Commission to said petitions for rehearing, the replies thereto, and of the letter citing additional authorities submitted by petitioner Tennessee Gas, it is

ORDERED, by the Court, that the aforementioned petitions for rehearing are denied.

Per Curiam
FOR THE COURT:

/s/ GEORGE A. FISHER
George A. Fisher
Clerk

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

September Term, 1979

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FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

COLUMBIA GAS TRANSMISSION CORP., et al.,
Intervenors

AND CONSOLIDATED CASES

Filed October 31, 1979

BEFORE: Wright, Chief Judge; McGowan, Tamm, Leventhal, Robinson, MacKinnon, Robb, and Wilkey, Circuit Judges

ORDER

The suggestions for rehearing *en banc* filed by petitioners Tennessee Gas Pipeline Co. and Transcontinental Gas Pipe

Line Corp., the response of respondent Commission to said suggestions for rehearing *en banc,* the replies thereto, and the letter citing additional authorities submitted by petitioner Tennessee Gas, all having been transmitted to the full Court and no judge in regular active service having requested a vote with respect thereto, it is

ORDERED, by the Court, that the aforesaid suggestions for rehearing *en banc* are denied.

Per Curiam
FOR THE COURT:

/s/ GEORGE A. FISHER
George A. Fisher
Clerk

APPENDIX E

UNITED STATES OF AMERICA

FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman; Albert B. Brooke, Jr., Pinkney Walker and Rush Moody, Jr.

Accounting and Rate Treatment of Advance Payments Included in Account 166, Advance Payments for Gas Development and Production, Docket No. R-411

ORDER NO. 465

ORDER AMENDING REGULATIONS UNDER THE NATURAL GAS ACT, UNIFORM SYSTEM OF ACCOUNTS FOR CLASS A AND CLASS B NATURAL GAS COMPANIES AND ANNUAL REPORT FORM NO. 2.

(Issued December 29, 1972)

On July 3, 1972 this Commission issued a renotice of its proposed rulemaking in Docket No. R-411 (37 F.R. 13559, July 11, 1972) proposing to determine whether the advance payment program is stimulating activity toward increasing the supply of natural gas sufficiently to justify the extension of rate base treatment of advances made after December 31, 1972.[1]

In addition, on October 24, 1972, this Commission issued a notice (37 F.R. 23363, November 2, 1972) requesting comments on or suggested modifications of our proposed rulemaking Docket No. R-411 based on the review of the sum-

[1] Termination date set in Order No. 441, issued November 10, 1971, in Docket No. R-411, 46 FPC 1178.

mary[2] of responses to the questionnaire[3] filed by all pipeline companies that filed advance agreements with us in accordance with Order Nos. 410 (44 FPC 1142) and No. 410-A (45 FPC 135), Docket No. R-380, and Order No. 441, *supra* (36 F.R. 21961), Docket No. R-411.

The object of the notice on July 3, 1972, was to afford all parties further opportunity to comment on (1) the question of continuing the rate base treatment of advances beyond the December 31, 1972, termination date; (2) allowing exploration and lease acquisition costs to be included in Account 166 to receive rate base treatment; (3) treating specified advances to pipeline affiliates the same as similar advances to independent producers; and (4) requiring simple interest at the rate of 7% per year to be paid by the producer to the pipelines on such advances. Comments were invited from interested parties to be submitted by July 31, 1972, on the Renotice of Proposed Rulemaking and by November 3, 1972, for comments on the Summary of Responses to the Commission questionnaire, FPC Form No. 102, "Survey of Status of Development Under Terms of Advance Payment Agreement."

The total of 49 respondents[4] filing comments in the Commission's Renotice of Proposed Rulemaking in Docket No. R-411 consists of 21 independent producers (including 7 small producers), 13 interstate pipelines, 3 distributors and 8 affiliated companies making separate filings. Two

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[2] "Summary of Advance Payment Status Report," (accumulated and tabulated by the F.P.C. staff) in the public file and available for inspection in the Commission's Office of Public Information and included in Attachment D to this order. [Editor's note: Omitted in printing].

[3] Responses to the Commission's questionnaire are in the public file and available for inspection in the Commission's Office of Public Information.

[4] See Attachment A, List of Respondents.

Associations and 2 State Commissions also filed comments. Four respondents requested a conference to discuss the Renotice, but because of the time element and the apparent completeness of the responses, the conferences were not scheduled.

Many respondents, in answering the four specific questions posed by us in the Renotice, expressed reservations, qualifications or suggested variations. Producers, pipelines, distributors and the associations overwhelmingly stressed higher field prices for both new and flowing gas as the only practical solution to the critical natural gas supply problem.

Sixteen producers (including the 7 small producers), 9 pipelines, 3 distributors, 4 affiliated companies, 2 associations and 1 state commission generally favored continuation of advances beyond the December 31, 1972, cutoff date established by Order No. 441. Three producers, 4 pipelines, 4 affiliated companies and 1 state Commission opposed continuation.

Five pipelines reported substantial success in acquiring new gas reserves through the advances program. Information submitted on the questionnaires filed by these companies complements their conclusion. One of the most aggressive of the companies using the advances program stated "advance payments are virtually the only means by which pipeline companies are presently able to acquire gas reserves on a long term basis," stating further that advances activity has been greatly reduced under the more restrictive requirements of Order No. 441.

Another pipeline, on the other hand, which has just recently become active in the advances program reported that in their experience it is the small independent producers that are making a significant portion of the discoveries in their area and are particularly dependent on advances since many operate with marginal capital and have limited access to conventional sources of financing.

Statements by the small producer respondents confirm this comment. One small producer reported drilling 114 oil and gas wells in 1971 and is continuing an aggressive exploration and development program in 1972. Another small producer reported having participated in exploration programs in the offshore area of Southern Louisiana, assisted by advance payments from an interstate pipeline. Still another reported that it has drilled 9 gas discovery wells since November 1970 and has contracted for advances based on computed reserves of each well.

Six respondents referred to their previous statements in Docket Nos. R-380 and R-411 to support their position in opposition to extending rate base treatment of advances beyond December 31, 1972. Two pipelines also contend their capital structure is weakened and they will have difficulty funding new facilities if the advances program is continued.

Three producers based their opposition on the argument of possible discrimination by the interstate pipelines in favor of their producing affiliates over the non-affiliated independent producers.

Responses to our question as to whether lease acquisition and exploration costs should be allowed rate base treatment showed 16 supporting, 16 opposing, 8 limiting rate base treatment to exploration costs and excluding lease acquisition and 9 respondents taking no position. Those opposing inclusion of these advances in rate base (Account 166) argue that any attempt to add to proven reserves by stimulating drilling activity will necessarily increase lease costs by virtue of more producers competing for a limited number of leases, without producing corresponding increases in proven reserves of gas. Those approving the inclusion of these advances in Account 166 argue that since Order No. 441 excluded these advances from rate base, the level of advances has seriously declined.

Our policy of treating independent producers and pipeline affiliates alike is supported by 25 respondents who favor allowing rate base treatment of advances to a pipeline affiliated producer. Ten respondents (7 large producers, one small producer, a producer association and a state commission) oppose such treatment citing economic advantage and preferential treatment because of affiliate relationships.

The question of requiring the producers to pay 7 percent simple interest on advances was opposed by 32 respondents with only three supporting the proposal. Fourteen respondents did not comment. Most respondents opposing the interest requirement commented that this would offset the basic incentive of the advances program and would be counter-productive.

We issued on October 24, 1972, "Notice of Comment Period on Summary of Responses to the Renotice," (37 F.R. 23363, November 2, 1972) to give interested parties an opportunity to comment on the Summary of Advance Payment Status Report, compiled from the questionnaire. (See Footnote 2 above)

Nine respondents [5] filed comments on the summary, maintaining their positions taken in response to our original notice of proposed rulemaking in Docket No. R-411. Respondents opposing continuation of rate base treatment of advances challenge both the significance of the data reported as well as its accuracy and adequacy. Two of these parties have attempted to make a cost determination by simply dividing total dollars advanced by the total reserve volume currently reported by the pipelines. This approach ignores the repayment requirements of the advance agreements as well as the fact that the cost passed on to the consumers is limited to the return on rate base and related taxes. Also ignored is the fact that exploration and devel-

[5] See Attachment B, List of Respondents.

opment programs funded by the advances have not been completed, particularly those supported by advances, subject to Order No. 441, which have been in effect less than a year. Consequently the reserve volumes attributable to advances programs can reasonably be expected to increase when the drilling programs are completed.

Upon review of the responses to the Renotice of Proposed Rulemaking Docket No. R-411, the data filed by the pipelines in answer to our advance payment questionnaire, the responses filed on the notice of the summary of the data compiled by this Commission in response to the questionnaire, and other data available to us, the following determination have been made:

All advances for which a contractual agreement was executed prior to the issuance of this order shall receive rate base treatment in accordance with the provisions of Order Nos. 410 and 410-A in Docket No. R-380 or Order No. 441 issued in this docket, as appropriate. Advances for which contractual agreements were executed on or after the date of issuance of this order shall be treated as ordered herein. For rate base purposes advances to pipeline affiliated producers shall be treated the same as advances to independent producers.

Attachment D schedules II(a) and (b) show that Proved Reserves [6] obtained in the Lower 48 amount to 8.7 trillion

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[6] Proven reserves of natural gas are the estimated quantities of natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known natural oil and gas reservoirs under existing economic and operating conditions.

Reservoirs are considered proven if economic producibility is supported by either actual production or conclusive formation tests. The area of a reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil, gas-water, or oil-water contacts; and (2) the adjoining portions not yet drilled but which can be reasonably judged as economically productive on

cubic feet (Tcf) from advances subject to Order Nos. 410 and 410-A and 0.8 Tcf from advances subject to Order No. 441 for a total of *9.5 Tcf*. Assuming that the total of pre-441 advances in the lower 48 states ($481,849,239) are recovered on the average in 5 years, there is a one year lag between the advance and commencement of recoupment and an average cost to the consumer of 13% for return and taxes; we estimate that the added cost to the consumer for the 8.7 Tcf of proven reserves will be approximately 2.5¢ per Mcf over the field price of gas purchased from those reserves.

Considering that the above reported data shows that advances to date have resulted in the addition of approximately nine and one half Tcf of proven gas reserves in the lower 48 states and in view of our analysis of all of the responses to the renotice and our review of the program of advances in general, we find that rate base treatment of advances to producers has "represented a justifiable experiment in the continuing search for solutions to our nation's critical shortage of natural gas." [7] Therefore, in view of the "temporary nature * * * and * * * ongoing experimental character" [8] of the advances program, it is reasonable and

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the basis of available geological and engineering data. In the absence of information of fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proven limit of the reservoir.

Reserve estimates are prepared for total recoverable natural gas, nonassociated gas and associated-dissolved gas. Estimates do not include (1) gaseous equivalents of natural gas liquids expected to be recovered from reservoir natural gas it is produced; or (2) nonhydrocarbon gases.

[7] *Public Service Commission of New York* v. *F.P.C.*, 467 F. 2d 370 (CADC-1972) denying rehearing to 467 F. 2d 361 (CADC-1972).

[8] *Public Service Commission of New York* v. *F.P.C., supra,* issued March 29, 1972.

appropriate that the program be extended for the period ending December 31, 1973, and that all advances made pursuant to contractual agreements executed after the issuance of this order, but not later than December 31, 1973, be made subject to the provisions of this order.

In Order No. 441 we stated:

> No advance may be included in Account 166 unless such advance is to be repaid in full by either delivery of natural gas or other consideration. Such repayment shall be completed within 5 years or as otherwise authorized by the Commission, from the date gas deliveries commence or the date it is determined that recovery will be in other than gas.

Our purpose in requiring the full recoupment of the advances was to ensure that the customers of the pipeline would not be charged for a project which resulted in a total or partial failure. This objective may also be accomplished by requiring the advancing pipeline itself to absorb any amounts of the advance not recovered either by gas or other economic consideration from the recipient of the advance. We adopt this approach in light of our initial and continuing intention to treat these advances as interest-free loans from the pipeline. Also, this approach will afford the pipeline added flexibility in negotiating with producers.

However, if 5 years elapses from the time the advance has been included in Account 166 and during such time no gas deliveries have commenced *or* no determination has been made that the recovery will be in economic consideration other than gas, the pipeline shall at the end of the 5-year period, remove the advance from Account 166 and cease rate base treatment thereof, unless otherwise directed by the Commission.

Moreover, if an advance which is or has been included in Account 166 results in the finding of proven reserves of

natural gas, gas deliveries commence, but no gas flows to the advancing pipeline, the advance shall be removed from Account 166 immediately, if not already removed, and any revenues collected as a result of the advance being included in rate base shall be refunded by the pipeline company to their customers within 12 months after the removal of the advance from Account 166, unless otherwise directed by the Commission. Where there is partial recovery of the advance by gas, the amount of the advance removable from Account 166 and the amount of revenues refundable, shall be appropriately apportioned. It should be noted that, in considering rate base treatment for these advances, the Commission will consider whether or not a sufficient portion of the reserves found or expected to be found as a result of the advance is dedicated to the pipeline making such advance.

Our renotice of rulemaking herein sought comments as to the advisability of requiring an annual interest rate of 7 percent on advance payments made to producers by pipelines. Our main concern is that the pipeline's customers be protected from the risk of nonrecoverable advances, and if the pipeline and producer can agree to meet that objective, it is not appropriate for us to require a 7 percent annual interest rate to be paid to the pipeline by the producer. The great majority of those commenting on this issue indicated that the interest charge would offset the basic incentive of the advances program and would be counter-productive by making advances a less attractive source of funds to producers. Therefore, the 7 percent interest provision will not be adopted.

In Order No. 441 we excluded advances for exploration and lease acquisition from rate base (Account 166) because we found at that time:

> that advances for exploration and lease acquisition have not (been) shown to be an effective vehicle for

> stimulating the widespread participation (of pipelines) in natural gas production for which their encouragement was intended.

Turning now to Attachment D, schedule II(a) we find that Proved Reserves of 5.58 Tcf, all in the lower 48 states, have been developed from such advances under Order Nos. 410 and 410-A. Perhaps more significantly, we find that of the total dollars advanced in the lower 48 states ($491,949,-239), 67% ($329,502,382), was for Lease Acquisition and Exploration and the resulting volume of Proved Reserves represents 64% of the total Proved Reserves (8.7 Tcf) developed in the Lower 48. If the total Proved and Potential Reserves in that area (8.7 Tcf plus 4.2 Tcf or 12.9 Tcf) were considered then Lease Acquisition and Exploration account for 8.74 Tcf or 68% of all the reserves developed in the Lower 48.

It is clear then that advances for exploration and lease acquisition have resulted in significant production activity. However, the comments indicate that advances for lease acquisition may have been a contributing factor in the bidding up of the price of the leases. Therefore we shall henceforth allow advances for exploration in rate base while continuing to exclude advances for lease acquisition from rate base.

In Order No. 441, we also imposed restrictions on rate base treatment of advances when a working interest or economic interest was retained by a pipeline affiliate. Upon review of the comments and the situation in general, we find that such treatment is inconsistent with out stated policy of treating pipeline affiliates equally with independent producers. As we stated in Opinion No. 568 (42 FPC 738 at 743, 752);

> Pipeline producers are henceforth to be treated on a parity with independent producers. By so doing we are encouraging *intensified exploration by the pipeline producers.* (Emphasis added) We would anticipate that gas produced from leases acquired after the issuance of this opinion would be promptly dedicated in the public interest to assure the adequacy of the supply of natural gas.

The majority of respondents agree with this position, stating that disallowing a working or other economic interest to a pipeline affiliate offers no economic advantage. It should be noted that under Order No. 441 pipeline affiliates, upon receipt of an advance, do not have the degree of freedom that independent producers have to negotiate agreements with other producers to develop the gas. Moreover, if a pipeline affiliate is allowed a working or economic interest, the cost to the customers of the pipeline is the same as when a pipeline makes an advance to an independent producer and retains no working or other economic interest. For these reasons, advances by the pipeline company to its affiliate who obtains a working or other economic interest, may include such advances in the rate base (Account 166). However, as noted above, advances shall not be used for lease acquisition.

Order Nos. 410, 410-A, and 441 allowed only advances made to producers within the lower 48 states to be included in Account 166 and receive rate base treatment. This same restriction shall apply to advances subject to this order. The proper treatment for advances made in the North American continent outside the lower 48 states where such production will be accessible by pipeline to the lower 48 states is the subject of a Notice of Proposed Rulemaking in Docket No. R-466 issued simultaneously with this order.

To better reflect the intentions of Accounts 166 and 167, we are revising the titles to read:

> 166 Advances for gas, exploration, development and production
>
> 167 Other advances for gas

Consistent with the amendments to Section 154.63 of the Regulations under the Natural Gas Act adopted herein, the Commission plans to consider those amounts allowed in Account 166, as rate base items, where found reasonable and appropriate.

The Commission finds:

(1) The notice and opportunity to participate in this proceeding with respect to the matters presently before this Commission through the submission, in writing, of data, views, comments and suggestions in the manner as described above are consistent and in accordance with all procedural requirements therefor as prescribed in Section 553 of Title 5 of the United States Code.

(2) The amendments of this Commission's Uniform System of Accounts, Regulations under the Natural Gas Act and Annual Report Form No. 2 schedules herein prescribed are necessary and appropriate for the administration of the Natural Gas Act.

(3) Since the revised schedules of FPC Form No. 2 are being prescribed for the reporting year 1972, good cause exists for making the amendments adopted herein effective immediately.

(4) Since the amendments prescribed herein, which are not included in the notice of this proceeding, are consistent with the prime purpose of the Proposed Rulemaking, further compliance with the notice provision of 5 U.S.C. 553 is unnecessary.

This Commission acting pursuant to the authority granted by the Natural Gas Act, as amended, particularly by Sections 4, 5, 7, 15, and 16, 52 Stat. 822, 823, 824, 825, 829 and 830 (1938); 56 Stat. 83, 84, (1942); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. 717c, 717d, 717f, 717n, and 717o, *orders:*

(A) This Commission's Uniform System of Accounts for Class A and Class B Natural Gas Companies prescribed by Part 201, Chapter I, Title 18 of the Code of Federal Regulations is amended as follows:

1. In the Chart of Balance Sheet Accounts, the title of account "166, Advance Payment for Gas Development and Production," and account "167, Other Advance Payments for Gas" is amended. As so amended, the chart of accounts read:

BALANCE SHEET ACCOUNTS

(Chart of Accounts)

• • • • • • •

ASSETS AND OTHER DEBITS

• • • • • • •

3. Current and Accrued Assets

• • • • • • •

166 Advances for gas exploration, development and production.

167 Other advances for gas.

• • • • • • •

2. In the Balance Sheet Accounts section, the title and text of account "166, Advance Payments for Gas Development and Production" and account "167, Other Advance Payments for Gas," is amended to read as follows:

BALANCE SHEET ACCOUNTS

ASSETS AND OTHER DEBITS

• • • • • • •

3. Current and Accrued Assets

• • • • • • •

166 Advances for gas exploration, development and production.

A. This account shall include all advances made within the lower 48 states for gas (whether called "advances," "contribution," or otherwise) to others, including advances to affiliated or associated companies; for exploration, development or production (but not to include lease acquisition) of natural gas, when such advances are to be repaid in full by either delivery of gas or other consideration. Under each agreement with payee, such payments must be made prior to initial gas deliveries, or if the agreement provides for advances on a well by well basis, each incremental payment must be made prior to deliveries from an incremental well, or prior to Federal and/or State authorization, as appropriate. Noncurrent advances not to be repaid within a two-year period shall be reclassified and transferred to account 124, Other Investments, for balance sheet purposes. This transfer is for reporting purposes only and has no effect on accounting or rate making.

B. When a pipeline obtains a working interest as a result of funds advanced to producers, such amounts shall be included in appropriate production accounts. When an associated company obtains a working interest as a result of funds advanced from a pipeline company, the pipeline shall include such amounts in Account 123, Investment in Associated Companies, or Account 146, Accounts receivable from Associated Companies, as appropriate, for formal contractual commitments made during the period of November 10, 1971 (effective date of Order No. 441), to the date of the issuance of Order No. 465.

C. Outstanding advances shall be fully reduced within 5 years, or as otherwise authorized by the Commission, from the date gas deliveries commence or the date it is determined that recovery will be in other than gas. This account shall be credited with advances not fully recovered within the five-year period, and the unrecovered portion charged directly to Account 426.5, Other Deductions. A sufficient portion of all gas taken should be credited to the related

outstanding advance so as to eliminate the advance within the 5-year period or as otherwise authorized by the Commission upon request by the pipeline company. The reduction of the outstanding advance should not be dependent on a buyer purchasing more than 100 percent of the minimum take or pay quantity provided in the contract.

D. Where recovery is by gas, recovered advance shall be credited to this account and charged to the appropriate gas purchase account.

E. When an advance results in a source of proven reserves of natural gas, but none flows to the pipeline company making such advances, the amount of the advance shall be removed from this account and recorded in Account 167. Any revenues collected as a result of the advance being included in rate base shall be refunded by the pipeline company to their customers within 12 months after the removal of the advance from this account, unless otherwise directed by the Commission. Where there is partial recovery of the advance by gas, in this situation, the amount of the advance transferred from this account to Account 167 and the amount of revenues refundable shall be appropriately apportioned.

F. If 5 years elapses from the time the advance has been included in this account and during such time no gas deliveries have commenced *or* no determination has been made that the recovery will be in economic consideration other than gas, the pipeline shall at the end of the 5-year period, transfer the advance from this account to Account 167, and cease rate base treatment thereof, unless otherwise directed by the Commission.

G. Whenever as a result of an advance included in this account, a pipeline receives any amount in excess of a full recovery of the advance, such amount must be credited to account 813, Other Gas Supply Expenses. If the income or

return is received in other than money, it shall be included at the market value of the assets received.

H. If the recipient of an advance is unable to repay it in full, through no fault of the pipeline or contractual provisions, in gas or other assets, the unpaid or nonrecoverable portion must be credited to this account at the time such amount is recognized as nonrecoverable. Nonrecoverable advances significant in amount must be eliminated within 5 years from the date of determination as nonrecoverable by either a charge to account 435, Extraordinary Deductions, or when authorized by the Commission, by a transfer to account 186. Miscellaneous Deferred Debits, and amortization to account 813, Other Gas Supply Expenses. Nonrecoverable advances insignificant in amount should be charged directly to account 813 in the year recognized as nonrecoverable.

I. No transfers shall be made from this account to any other accounts, unless otherwise provided herein, except as authorized by the Commission upon request by the pipeline company.

J. Three copies of any agreement concerning advances will be filed with the Secretary within 30 days of the initial related entry in account 166.

Note A: This account may include advances for exploration (including lease acquisition costs) made according to the provision of Order Nos. 410 and 410-A, for which a contractual commitment was made prior to the date of Order No. 441. All advances made from October 2, 1970 (issue date of Order No. 410), to November 10, 1971 (issue date of Order No. 441), shall be subject to the provisions of Order Nos. 410 and 410-A.

Note B: This account shall not include advances for exploration (including leace acquisition costs) in accordance with Order No. 441, for which a contractual commitment was made from November 10, 1971 (issue date of Order No. 441), to the date of the issuance of Order No. 465.

Note C: All advances made from November 10, 1971 (issue date of Order No. 441), to the date of the issuance of Order No. 465 shall be subject to the provisions of Order No. 441.

Note D: This account shall not include advances expended for delay rentals, nonproductive well drilling or abandoned leases where such advances are related to lease acquisition, except in accordance with Note A and Note B to this account.

Note E: To keep the Commission informed when an advance is nonrecoverable by any means the company must submit the full details including copies of Federal and State plugging and abandonment reports involved as soon as such fact becomes known.

167 Other advances for gas.

This account shall include all advances not properly includible in Account 166, exclusive of amounts advanced where a working interest is obtained.

(B) The schedule pages 110, entitled Comparative Balance Sheet—Statement A, 210 A, Gas Prepayment under Purchase Agreements, and 210 B, entitled Advances for Gas Prior to Initial Deliveries or Commission Certification (Account 124, 166, and 167), in F.P.C. Form No. 2, Annual Report for Natural Gas Companies (Class A and Class B) prescribed by § 260.1, Chapter I, Title 18 of the Code of Federal Regulations is amended as set out in Attachment C hereto.*

(C) Statement E—Working Capital, in paragraph (f) Description of statements, of § 154.63 in Part 154, Rates

* Omitted in printing.

Schedules and Tariffs, Subchapter E-Regulations under the Natural Gas Act, Chapter I, title 18 of the Code of Federal Regulations is amended as follows: Item (b) in the first sentence of the second paragraph of Statement E is revised by changing the date following the words "prior to" from "January 1, 1973," to "January 1, 1974," Schedules E-1 and E-2 are also amended. As amended, this portion of Statement E reads as follows:

§ 154.63 Changes in a tariff, executed service agreement or part thereof.

* * * * * * *

Description of Statements. * * *

* * * * * * *

Statement E—*Working Capital.* * * *

The components of working capital may include (a) * * * (b) an allowance for the average of 13 monthly balances of materials and supplies, prepayments, the unrecovered portion of advances to suppliers in Account 166 made under contracts executed prior to January 1, 1974, and gas for current delivery from underground storage. * * *

Schedule E-1 setting forth monthly balances for materials and supplies, prepayments, and advances in such detail as to disclose, either by subaccounts regularly maintained on the books or by analysis of the principal items included in the main account, the nature of the charges included therein.

Schedule E-2 setting forth monthly balances of material and supplies, prepayments, and advances on purchased gas for two years immediately preceding the 12 months of actual experience used in the filing. * * *

(D) Subparagraph (c) of Section 260.1, Part 260, Subchapter G, Chapter I, Title 18 CFR, is amended by adding a new schedule title, "Advances for Gas Prior to Initial Deliveries or Commission Certification (Accounts 124, 166 and 167)" immediately following, "Prepaid Gas Purchases Under Purchase Agreements." As amended, the subparagraph reads:

§ 260.1 Form No. 2, Annual report for natural gas companies (Class A and Class B).

* * * * * * *

(c) This annual report contains the following schedules:

* * * * * * *

Advances for Gas Prior to Initial Deliveries or Commission Certification (Accounts 124, 166, and 167).

Advances for Gas Prior to Initial Deliveries or Commission Certification (Accounts 124, 166, and 167).

(E) This order is effective immediately upon issuance.

(F) The Secretary of the Commission shall cause prompt publication of this order to be made in the Federal Register.

Attachment A

DOCKET NO. R-411 (RENOTICE)

LIST OF RESPONDENTS

Associations

Associated Gas Distributors (representing 54 companies)
The Independent Petroleum Association of America (IPAA)

Gas Companies

Cities Service Gas Co.
Colorado Interstate Gas Co., a division of Colorado Interstate Corp.
Columbia Gas Transmission Corp.
El Paso Natural Gas Co.
Florida Gas Transmission Co.
Iroquois Gas Corp.

Michigan Gas Storage Co.
Michigan Wisconsin Pipe Line Co.
Natural Gas Pipeline Co. of America
Northern Illinois Gas Co.
Pacific Gas and Electric Co.
Pacific Gas Transmission Co.
Panhandle Eastern Pipe Line Co.
Trunkline Gas Co.
Peoples Gas Light and Coke Co., The
Southern California Gas Co.
Southern Natural Gas Co.
Tennessee Gas Pipeline Co., a division of Tenneco Inc.
Texas Eastern Transmission Corp.
Transwestern Pipeline Co.
Texas Gas Transmission Corp.
Transcontinental Gas Pipe Line Corp.
United Gas Pipe Line Co.

Independent Producers

Adobe Oil Co.
Amoco Production Co.
Atlantic Richfield Co.
Bass, Perry R., *et al.*
The California Co., a division of Chevron Oil Co.
Cities Service Oil Co.
Clark Oil Producing Co.
Continental Oil Co.
Gulf Oil Corp.
Hickerson Oil Co.
Hughes, Kingdon R.
Humble Oil & Refining Co.
Leede, Edward H.
Marathon Oil Co.
Mesa Petroleum Co.
Mobil Oil Corp.
Pennzoil Producing Co.
Pennzoil Offshore Gas Operators, Inc.

Phillips Petroleum Co.
Placid Oil Co.
Shell Oil Co.
Sun Oil Co.
Superior Oil Co., The
Tripperary Land & Exploration Corp.

State Commissions

People of the State of California and the Public Utilities Commission of the State of California
Public Service Commission for the State of New York

Attachment B

RESPONDENTS TO DOCKET NO. R-411 (RENOTICE)

Notice of Comment Period on Summary of Responses to Renotice (Questionnaire)

Associations

Associated Gas Distributors

Gas Companies

Consolidated Gas Supply Corp.
Northern Natural Gas Co.
United Gas Pipe Line Co.

Producers

Atlantic Richfield Co.
Continental Oil Co.
Gulf Oil Corp.
Mobil Oil Corp.

State Commissions

Public Service Commission for the State of New York